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Solid Waste

EPA

Technical Report

Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy

An Interim Report on Methodology for Data Collection and Analysis

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Introduction

GENERAL INTRODUCTION

Regulatory Background

Under Section 3001 (b)(2)(A) of the 1980 amendments to the Resource Conservation and Recovery Act (RCRA), Congress temporarily exempted several types of solid wastes from regulation as hazardous wastes, pending further study by the Environmental Protection Agency (EPA).[1] Among the categories of wastes exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy."

Section 8002(m) of the amendments required the Administrator of EPA to conduct a study and submit a final report to Congress by October 1982. EPA did not conduct the study.

In its study of these wastes, Congress directed EPA (through RCRA section 8002(m)) to consider:

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[1]EPA is also required to make regulatory determinations affecting the oil and gas and geothermal energy industries under several other major statutes. These include designing appropriate effluent limitations guidelines under the Clean Water Act, determining emissions standards under the Clean Air Act, and implementing the requirements of the underground injection control program under the Safe Drinking Water Act.

1. The sources and volumes of discarded material generated per year from such wastes;

2. Present disposal practices;

3. Potential danger to human health and the environment from the surface runoff or leachate;

4. Documented cases that prove or have caused danger to human health and the environment from surface runoff or leachate;

5. Alternatives to current disposal methods;

6. The cost of such alternatives; and

7. The impact of those alternatives on the exploration for, and development and production of, crude oil and natural gas or geothermal energy.

In August 1985, the Alaska Center for the Environment sued EPA (Alaska Center for the Environment v. Lee Thomas) for its failure to conduct the study. EPA then signed a consent order obligating it to submit the final Report to Congress on or before August 31, 1987. In the interim, the Agency must meet several requirements by specific dates. One such milestone is to complete the present Technical Report by October 31, 1986.

All of the information and methods presented in this Technical Report are preliminary and subject to revision. *Comments are solicited and encouraged on any portion of the document.*

Pursuant to the consent degree, EPA is preparing a separate technical report that will characterize wastes associated with oil and gas extraction. Information and analytical data necessary for waste characterization were collected in a nationwide screening sampling program that lasted from June through September of 1986. This information is now being interpreted and compiled and will be formally released, as required by the consent decree, in January of 1987.

Wastes Included Under the Exemptions

The legislative history of Section 3001(b)(2)(A) sheds some light on the identity of oil and gas and geothermal energy wastes subject to exemption:[2]

> The term "other wastes associated" is specifically included to designate waste materials intrinsically derived from the primary field operations associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy. It would cover such substances as hydrocarbon-bearing soil in and around facilities; drill cuttings; materials (such as hydrocarbon, water, sand, and emulsion) produced from a well in conjunction with crude oil, natural gas, or geothermal energy; and the accumulated material (such as hydrocarbon, water, sand, and emulsion) from production separators, fluid treating vessels, storage vessels, and production impoundments.
>
> The phrase "intrinsically derived from the primary field operation ..." is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.

Floor commentary on the exemptions consists of only a few brief statements of general support. The speakers note that muds and brines are exempted, and also specify that geothermal energy must be treated in a manner consistent with oil and gas extraction (125 Congressional Record, June 4, 1979).

Since the exact identity of the wastes exempted affects the scope of the present study, EPA has relied on RCRA's language and the legislative history to develop tentative criteria for determining which wastes are included:

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[2]Conference Report, 96th Congress, 2nd Session 32 (1980).

1. Only waste streams intrinsic to the exploration for, or development and production of, crude oil, natural gas, or geothermal energy are subject to exemption. Waste streams generated at oil, gas, and geothermal energy facilities that are not uniquely associated with exploration, development, or production activities are *not* exempt (one example would be spent solvents from equipment cleanup).

2. Exempt wastes must be associated with "extraction"[3] processes, which include measures (1) to remove oil, natural gas, or geothermal energy from the ground or (2) to remove impurities from such substances, provided that the purification process is an integral part of normal field operations.[4]

3. The proximity of waste streams to primary field operations is a factor in determining the scope of the exemption. Process operations that are distant from the exploration, development, or production operations may not be subject to exemption.

4. Wastes associated with transportation are not exempt. The point of custody transfer, or of production separation and dehydration, may be used as evidence in making this determination.

As shown on Table 1, EPA has used these criteria to tentatively designate various wastes as exempt or not exempt. The Agency is aware that this table does not include all waste streams found at oil, gas, or geothermal extraction facilities. Therefore, EPA invites commenters to specifically describe other affected waste streams and to articulate, in terms of the above criteria, whether or not these additional streams are or are not subject to the Section 3001(b)(2)(A) exemption. EPA also invites comment on the criteria themselves and on the appropriateness of the tentative classifications shown on Table 1.

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[3]The term extraction is defined to include, exploration, development, and production activities for oil, gas, and geothermal energy.

[4]Thus, wastes associated with such processes as oil refining, petrochemical-related manufacturing, or electricity generation from geothermal energy are not exempt.

Table 1
Wastes Considered Exempt Under Section 3001(b)(2)

Oil and Gas	Geothermal Energy
• Drilling media	• Drilling media and cuttings
• Drill cuttings	• Reinjection well fluid wastes
• Well completion, treatment, and stimulation fluids	• Piping scale and flash tank solids (except for those associated with electrical power generation)
• Packing fluids	• Precipitated solids from brine effluent
• Produced waters	• Settling pond wastes
• Produced sand	
• Workover fluids	
• Field tank bottoms	
• Waste crude oil and waste gases from field operations	
• Waste triethylene glycol used in field operations	

Wastes Considered Not Exempt Under Section 3001(b)(2)

Oil and Gas	Geothermal Energy
• Waste lubricants	• Wastes resulting from the generation of electricity, such as: - hydrogen sulfide wastes - cooling tower drift - cooling tower blowdown
• Waste hydraulic fluids	• Waste lubricants
• Waste solvents	• Waste hydraulic fluids
• Waste paints	• Waste solvents
• Sanitary wastes	• Waste paints
• Refining wastes	• Sanitary wastes
• Waste motor oil	

Structure of This Report

Part I of this Technical Report presents an overview of the oil and gas extraction industry and describes EPA's proposed methodology for addressing the study areas mandated by RCRA Section 8002(m).

Part II of this report provides an overview of the geothermal energy industry and describes potential sources of wastes. It also identifies additional information needed to address RCRA's mandates.

Part III presents a methodology for collecting and presenting documented cases of damage caused by wastes associated with oil, gas, or geothermal energy extraction.

Part IV presents a methodology for preparing a risk assessment of the potential danger to human health and the environment from improper management of wastes from the oil, gas, and geothermal energy extraction industries.

Appendix A of this report summarizes State and Federal regulations currently affecting the oil and gas extraction industry. Summaries of State and Federal regulations affecting geothermal energy extraction have not yet been developed, but will be included in the Report to Congress due on August 31, 1987.

Appendix B of this report contains a brief glossary of terms and list of abbreviations relevant to the present report.

Part I

Oil and Gas

CHAPTER 1

OVERVIEW OF THE OIL AND GAS INDUSTRY AND WASTE GENERATION

INDUSTRY PROFILE

The onshore oil and gas industry is responsible for the exploration, development, and production of petroleum resources in the United States. Petroleum is a complex mixture of hydrocarbons occurring in the earth as gases, liquids, and solids. For the purposes of this discussion, oil is defined as crude petroleum oil and other hydrocarbons, regardless of gravity, which are produced at the wellhead in liquid form. Natural gas is any hydrocarbon fluid that is produced in a natural state from the earth and which maintains a gaseous state at 16°C (60°F) and standard atmospheric pressure. Gas liquids are the liquid hydrocarbons known as "natural gasoline" recovered from natural gas. In general, petroleum is a liquid (crude oil) that is recovered from within the earth through drilled bore holes. Liquid and gaseous petroleum occurs naturally underground, primarily in the pore spaces of sedimentary rocks.

Chemically, crude oil is composed of carbon and hydrogen (approximately 82-87 percent carbon, 12-17 percent hydrogen). Lesser quantities of sulfur, oxygen, and nitrogen organic compounds account for the balance of material. Crude oils are also classified as <u>paraffins</u>--organic compounds containing methyl-CH_4 structure, <u>napthenes</u>--organic compounds with C_nH_{2n} structure, and <u>aromatics</u> with C_nH_{2n-6}

structure. (The <u>n</u> denotes the number of carbon atoms in the hydrocarbon molecule.) A number of inorganic substances are also commonly found in crude oil. Sodium chloride, usually found dissolved in crude oil, comes from the aqueous medium which nearly always coexists underground with petroleum. Lesser quantities of free sulfur, hydrogen sulfide, and carbonyl sulfide also are found. Two metals--nickel and vanadium--are common to crude oils; these metals are present as metal porphyrins.

As of 1983, the earth's verified petroleum reserves totaled approximately 600 x 10^9 barrels (Kirk-Othmer, 1985). However, the rate of discovery of large petroleum reserves has steadily declined for the past four decades. Future demands will be met through exploration and discovery of new fields--operations that will become more costly as fewer and fewer reserves are located--and through the development of new extraction techniques to recover portions of crude petroleum left behind by conventional extraction methods. All of these elements will result in higher crude oil prices in the future.

<u>Exploration and Development Operations</u>

Exploration operations are those activities occurring in the search for petroleum in areas previously undeveloped with regard to petroleum reserves. These operations include activities associated with locating potential petroleum reserves (such as seismic exploration), well drilling, well stimulation, well completion, and/or well abandonment. Development operations are similar to exploratory operations except that developmental operations occur in the attempt to establish productive wells in areas known to contain petroleum reserves. Developmental operations are conducted in known reservoirs or oil fields, with the objective of further enhancing the productivity of an area. The vast majority of well drilling operations in the United States is developmental activity.

Petroleum is found and recovered on all of the earth's continents except Antarctica. In the United States, the first onshore oil well was drilled by Col. E. T. Drake near Titusville, Pennsylvania, in 1859. Drake struck oil at 69-1/2 feet from the surface. Since then, approximately 2.7 million oil and gas wells have been drilled in the United States.

Drilling activity in the United States is almost entirely limited to 32 States. As shown in Figure I-1, these States are grouped by petroleum-bearing basins, which are contiguous between many States. Alaska and California are notable exceptions.

From 1980 to 1986, onshore drilling activity proceeded at a rate averaging 80,000 wells per year (Oil and Gas Journal, 1985). However, in 1986 the worldwide drop in oil prices caused drilling activity to decrease by almost 50 percent (Oil and Gas Journal, 1986b). New wells range in depth from several hundred feet to over 20,000 feet.

Well Drilling

Rotary Mud Drilling. During the last five decades, rotary drilling has become the predominant drilling technique. A sketch of a typical rotary drilling rig is given in Figure I-2. Essentially, the bit and the drill pipe suspended above the bit are slowly rotated, gouging and chipping away the rock at the bottom of the well. As the well becomes deeper, additional sections of pipe are added. An advantage of rotary drilling is that it minimizes loss of crude oil and gas. The drill core is circulated with a weighted drilling fluid (called drilling mud)[1] that serves as a pressure seal for the well. As a rotary well is drilled, mud is circulated down the drill pipe where it picks up cuttings and carries them up the hole to the surface. At the surface, mechanical devices separate the mud from cuttings. The mud is recirculated; cuttings are

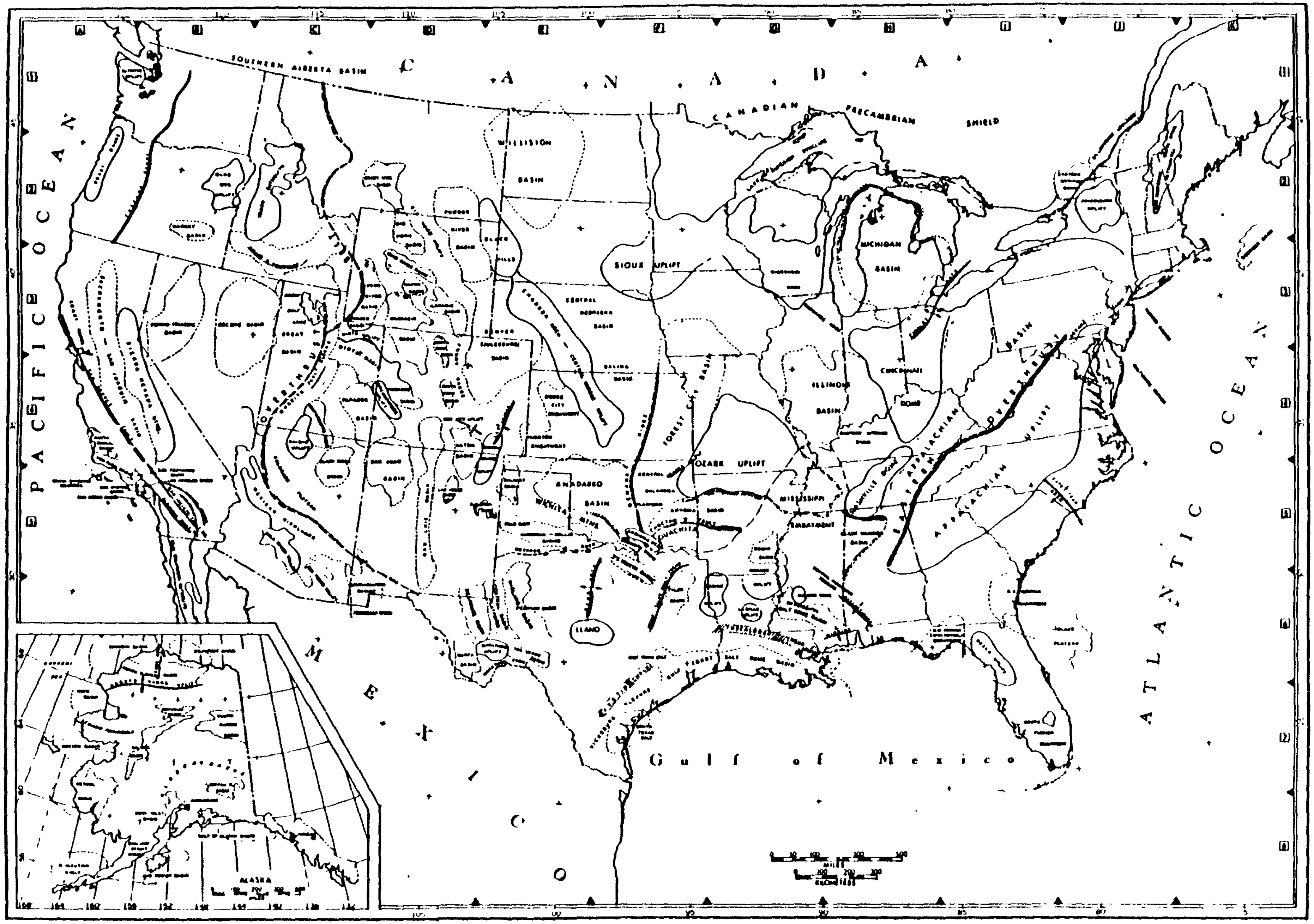

Figure I-1. Petroleum Basin Map of the United States

Note: Published by Pennwell Publishin

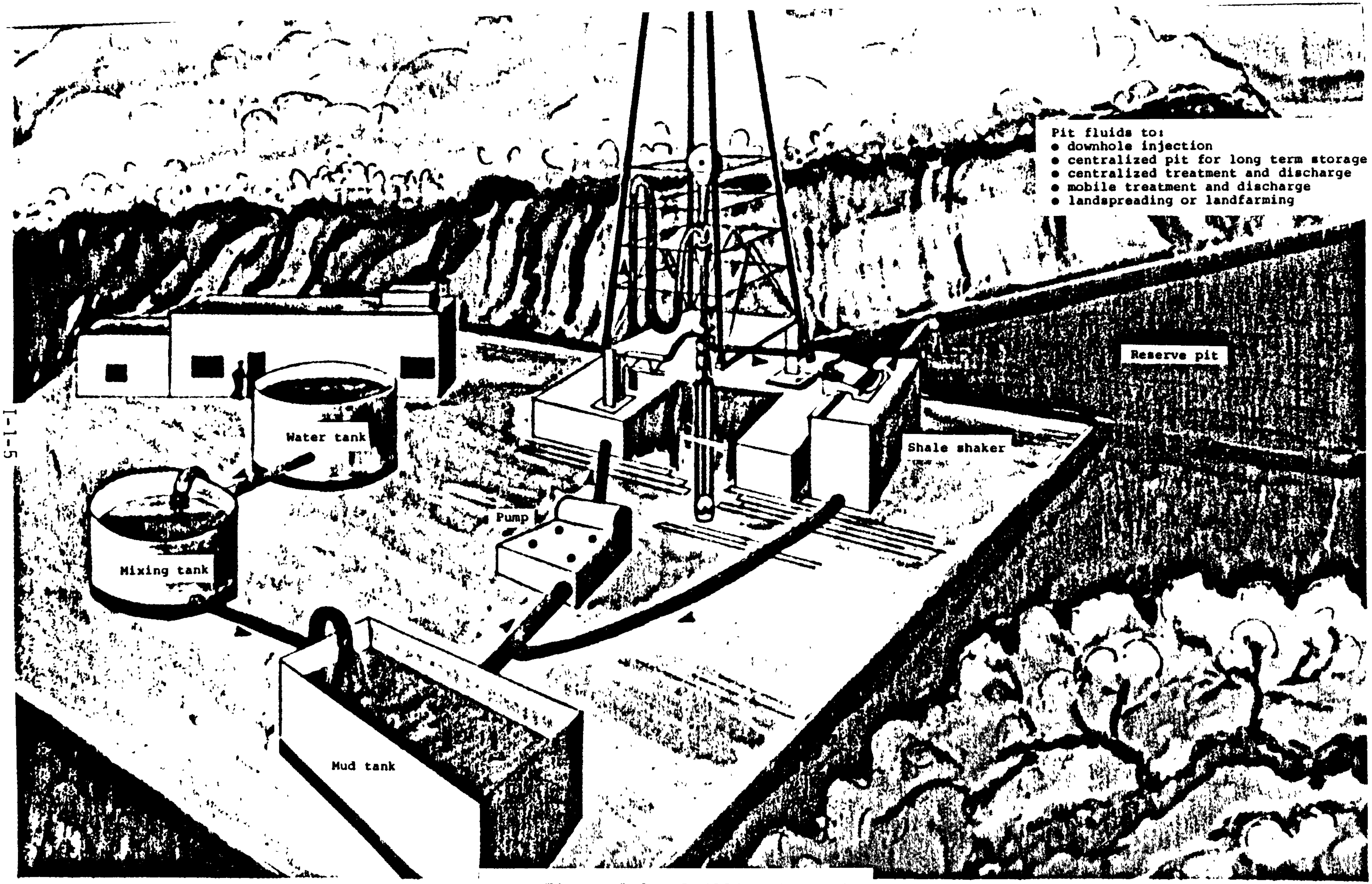

Figure I-2. Drilling Operation

displaced (with associated mud) into an earthen reserve pit. The reserve pit receives this mixture (and all the chemicals associated with these wastes) and rig deck drainage. Depending on the site, it may also receive sewage and other wastes. The following pits usually are associated with rotary mud drill sites: reserve pit(s), emergency pit, and/or fresh water pit (or tank). Most States have construction requirements or guidelines for these pits; many States have specific pit reclamation requirements (see Appendix A).

Rotary drilling techniques make it possible to drill wells over 20,000 feet deep. A recent development in rotary drilling has involved a fluid powered turbine at the bottom of the bore hole to provide the rotary motion of the bit. In this method, the drill pipe does not rotate, but is used to weight the bit and carry the drilling mud to turn the turbine.

Pneumatic Drilling. Pneumatic drilling is another boring method used in the Appalachian Basin, in southeastern Kansas/northeastern Oklahoma, in the four corners area of the southwest, and in the Rocky Mountain States (see Figure I-1). Pneumatic drilling may be favored over rotary drilling when the underlying formations are hard rock or in shallow locations where the use of fluids to maintain subsurface pressure is not required. In these circumstances, pneumatic drilling is considerably faster and less

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1 Special chemical fluids are introduced into the bore hole to lubricate the action of a rotary bit, to remove the cuttings, and to prevent blow-outs. Drilling muds circulate continuously down the drill pipe, into the bore hole, and upwards between the drill pipe and the walls of the hole to a surface pit, where they are purified and recycled. The composition of drilling muds may vary. They can be oil or water base; all contain high concentrations of solids such as barite, calcium carbonate, or clays. The mud is maintained as a suspension with emulsifiers, wetting agents, and other specialty chemicals.

expensive than rotary mud drilling. In pneumatic drilling, air usually is the drill medium. Compressed air drives the drill bit and lifts cuttings back to the surface. Once the cuttings reach the surface, water is injected into the cuttings return line for dust control. This slurry of cuttings and water is deposited into an earthen waste pit at the drill site. When fluids are encountered during pneumatic drilling, foaming agents are used to bring the fluids to the surface. The fluid and foaming agents are also displaced into the waste pit. The pit may subsequently be treated with defoamants.

Cable-Tool Drilling. Early oil and gas wells were drilled with impact tools by a method called cable-tool drilling. In this drilling method, a chisel-like bit is suspended from a cable to a lever on the surface, and an up-and-down motion of the lever causes the bit to pound the bottom of the hole and chip away the rock. These wells must be free of liquids during the drilling process so that the bit can remove waste rock. When the bit penetrates the gas or oil formation, large quantities of gas and oil can flow rapidly ("blowout") to the surface. This "gusher" appearance gives the impression of a successful well when, in fact, these materials are wasted and can contaminate much of the surrounding countryside. (Drilling without protection against blowouts is now prohibited by State regulations.)

Well Logging

After the bore hole has penetrated the petroleum-bearing formation, the formation must be tested to determine if expensive completion procedures (described below) should be used. These evaluations are made with well logging measurement instruments that can detect the differences in rock, water, and petroleum. Only a production test can establish the potential productivity of a well. In this test--called a "drill stem" test - the bore hole is sealed above and below the petroleum formation, with only the drill pipe open to the formation. The drill pipe is then emptied of the drilling mud so that the crude oil can enter. After a time, the openings to the drill pipe are closed and fluids are brought to the surface. The fluids are then analyzed to determine their hydrocarbon content and quality. If there is gas in the formation, the gas will flow from the top of the drill pipe during the test.

Well Completion

If preliminary tests show that one or more of the formations in the bore hole will be commercially productive, the well must be prepared for the continuous production of the oil or gas. First, a large outside pipe, or casing, slightly smaller in diameter than the drill hole, is inserted to the full depth of the well. A cement slurry is forced between the outside of the casing and the inside surface of the drill hole. When set, this cement forms a seal so that fluids cannot communicate from one portion of the well to the other through the bore hole. In the continental U.S., the casing is usually about 23 centimeters (9 inches) in diameter. It creates a permanent well through which the productive formations may be reached. After the casing is in place, a production string of smaller (8 centimeters, or 3 inches in diameter) tubing is extended from the surface to the productive formation. A packing device is used to seal the productive interval from the rest of the well. If multiple productive formations are found, as many as four production strings of tubing may be hung in the same cased well.

Since the casing is sealed against the productive formation, openings must be made to allow the oil or gas to enter the well. A down-hole perforator uses an explosive to shoot holes through the casing and cement and into the formation. The perforating tool is lowered on a wire line. When it is in the correct position, the charges are triggered electrically from the surface. Such perforating will be sufficient if the formation is quite productive. If not, well stimulation techniques (described below) may be used to encourage production.

When the subsurface equipment is in place, a network of valves (called a "wellhead" or "Christmas tree") is installed on the surface and arranged so that flow from the well can be regulated and measured, and tools to perform subsurface work can be introduced through the tubing. The wellhead may be very simple, such as might be found on a low-pressure well that must be pumped, or it may be very complex, as in the case of a high-pressure well with multiple producing strings. Figure I-3 shows a wellhead.

Well completion fluids and well treatment fluids are generated during the processes described above. These wastes may include muds, additives, and hydrocarbons.

Well Stimulation

After drilling is completed, well stimulation techniques may be performed to enhance production. Acidizing is one of the original well stimulation techniques still in modern use. The first and by far the most successful well stimulation acidizing technique uses hydrochloric acid introduced into the petroleum-bearing formation. Hydrochloric acid

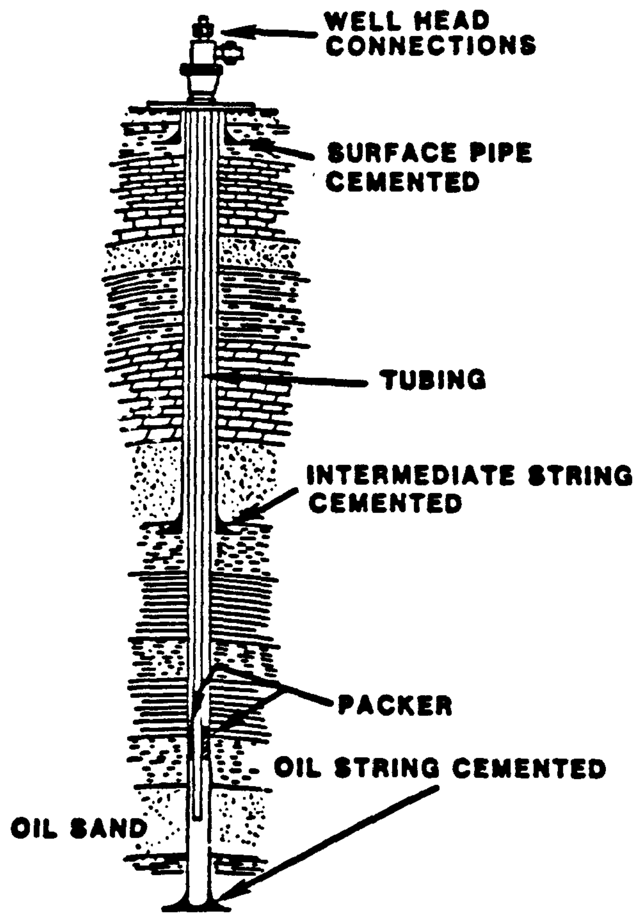

Figure I-3. Production well

Source: API. 1983. Introduction to Oil and Gas Production. Book 1 of Vocational Training Series, pp. 8, 19.

stimulation is used in dolomite and limestone formations. Hydrochloric acid treatment produces carbon dioxide, calcium chloride, and/or magnesium chloride.

Another acid treatment uses a solution of hydrochloric and hydrofluoric acids to stimulate wells in sandstone formations. In this instance, sodium fluoride is an additional reaction product. Other acidizing systems include:

- Organic acids - formic and acetic acid (usually used in combination with hydrochloric or hydrofluoric);
- Powdered acids - sulfamic acid, chloroacetic acid; and
- Retarded acid systems - gelled acids, chemical retarded acids, emulsified acids.

Other chemical agents that are added to petroleum wells to maintain or increase well productivity are the following:

- Corrosion inhibitors - to reduce the attack of acid on metal. Some of these contain arsenic compounds; many contain organic compounds.
- Surfactants - to demulsify acid and oil, reduce interfacial tension, alter formation wettability, speed cleanup, prevent sludge formation.
- Friction reducers - to minimize pumping energy. Usually these are organic polymers added to the stimulation fluids (guar, cellulose, fatty acids).
- Acid flow-loss additives - Composed of solid particles that enter formation pores, and a gelatinous material to plug pores, silica fluor, calcium carbonate, polyvinyl alcohol, polyacrylamide.
- Diverting agents - to direct stimulation fluids.

- Complexing agents - to solubilize iron and other pipe or metal corrosion products that might precipitate. Most satisfactory product is ethylene diamine tetracetic acid (EDTA).

- Cleanup additives - to cleanse the well of the reactor products and unusual reagents after acid treatment. These products are flushed with water and removed by use of nitrogen gas. Alcohols and wetting agents are added to ease these tasks (Williams, et al., 1979).

All water-soluble reagents, sludges, and organic residue will eventually be pumped from the well to the surface. In general, these wastes are displaced into a holding pond for treatment and disposal.

Production Operations

Production operations include all activities associated with the recovery of petroleum from geologic formations. Production operations are delineated into those activities associated with downhole operations (such as petroleum recovery techniques, workovers, and well stimulation techniques), and those activities associated with surface operations (such as oil/gas/water separation and treatment of oil, gas, gas liquids, or produced water).

In the United States, approximately 28 billion barrels of crude oil had been discovered as of December 1985. Less than one-half of these reserves will ultimately be recovered with existing technology and economic conditions. Unfavorable reservoir geology, adverse fluid properties, or low oil content in the reservoir rock limit recovery prospects for petroleum resources.

By 1984, there were 864,405 producing onshore oil and gas wells in the United States. These wells yielded 3.09 x 10^9 barrels of crude oil and 19 x 10^6MM cubic feet of gas annually[1] (Kirk-Othmer, 1985; IOCC, 1985).

Approximately 70 percent of the total number of oil wells in the United States are "stripper wells." Stripper wells are defined as those oil wells that produced less than 10 barrels of oil per day (44 FR 22069).

In addition to this production, the United States must import crude oil to augment its productive capacity.

Table I-1 presents 1984 onshore oil and gas production data for each State as reported by the Interstate Oil Compact Commission. The table contains each State's 1984 annual oil and gas production, total number of oil and gas wells, and number of stripper wells (IOCC, 1985; IOCC/NSWA, 1985).

Water is produced along with crude petroleum and/or natural gas. This water, called "produced water" or "brine," is an aqueous solution containing many dissolved chemicals, minerals such as sodium chloride and dissolved hydrocarbons. It can present major disposal difficulties. In several western States, produced water may be a vital source of water for livestock, which can tolerate higher sodium chloride concentrations than humans.

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1 The crude oil production unit has traditionally been the barrel, which is equivalent to $0.159M^3$, 42 U.S. gallons, or 5.61 ft^3.

TABLE I-1

ONSHORE OIL AND GAS PRODUCTION - 1984

	Total # Oil Wells	Annual Production MM BBL/YR	# Gas Wells	Annual Production MMSCF Gas	# Strippers
Alabama	797	24.0	659	130,080	98
Alaska	864	631.0	81	300,046	—
Arizona	26	0.2	5	225	14
Arkansas	9,490	18.5	2,492	162,678	4,738
California	48,908	411.7	1,220	470,124	26,650
Colorado	5,287	38.6	4,665	271,544	1,690
Connecticut	0	0	0	0	0
Delaware	0	0	0	0	0
Florida	165	17.2	0	15,404	165
Georgia	0	0	0	0	0
Hawaii	0	0	0	0	0
Idaho	0	0	0	0	0
Illinois	28,920	28.9	157	1,530	29,942
Indiana	6,792	5.4	1,194	394	6,134
Iowa	0	0	0	0	0
Kansas	57,633	96.7	12,680	466,590	45,749
Kentucky	19,980	11.8	9,013	61,518	16,433
Louisiana	28,068	604.7	16,815	5,867,511	16,500
Maine	0	0	0	0	0
Maryland	0	0	9	20	—
Massachusetts	0	0	0	0	0
Michigan	4,881	40.5	510	144,695	3,500
Minnesota	0	0	0	0	0
Mississippi	3,569	33.5	715	210,393	1,923
Missouri	557	0.1	0	0	548
Montana	4,665	30.7	2,152	56,895	3,085
Nebraska	2,072	6.6	18	2,347	1,700
Nevada	34	2.0	0	0	—
New Hampshire	0	0	0	0	0
New Jersey	0	0	0	0	0
New Mexico	24,954	129.9	17,523	965,717	14,749
New York	4,678	1.0	3,800	27,000	4,532
North Carolina	0	0	0	0	0
North Dakota	4,026	58.7	58	80,596	1,061
Ohio	26,878	15.3	27,846	186,480	25,129
Oklahoma	99,030	207.5	23,647	1,996,713	82,431
Oregon	0	0	6	2,790	—
Pennsylvania	20,739	4.8	24,050	166,342	19,540

TABLE I-1 (Continued)

ONSHORE OIL AND GAS PRODUCTION - 1984

	Total # Oil Wells	Annual Production MM BBL/YR	# Gas Wells	Annual Production MMSCF Gas	# Strippers
Rhode Island	0	0	0	0	0
South Carolina	0	0	0	0	0
South Dakota	141	0.7	41	2,468	30
Tennessee	775	0.9	726	5,023	744
Texas	203,178	1186.1	43,174	6,753,889	162,855
Utah	1,862	39.0	728	99,800	400
Vermont	0	0	0	0	0
Virginia	35	0.3	499	8,928	32
Washington	0	0	0	0	0
West Virginia	15,475	10.0	30,700	143,731	15,200
Wisconsin	0	0	0	0	0
Wyoming	12,463	143.4	2,280	600,137	5,020
Totals	636,942	3799.4	227,463	19,201,608	493,844

(—) No Data

Sources: Interstate Oil Compact Commission, The Oil and Gas Compact Bulletin, Vol. XLIV, No. 2. December 1985; Interstate Oil Compact Commission and the National Stripper Well Association, National Stripper Well Survey, January 1, 1985; Oklahoma City: Interstate Oil Compact Commission, October 1985.

Downhole Production Operations

Oil and Gas Recovery Techniques. Conventional primary and secondary recovery processes produce about one-third of the original oil discovered. These techniques are described below. Recovery efficiency is a result of a variation in the properties of the specific rock, the properties of the petroleum fluid involved from reservoir to reservoir, and the recovery technique(s) employed.

In all petroleum recovery methods, aqueous solutions are produced and must be treated, stored, recycled, or disposed of.

- Primary oil and gas recovery. "Natural drive" production relies on natural reservoir pressure to drive the oil through the complex rock pore network to the producing wells. The driving pressure is derived from the expansion of liquid and the release of dissolved gas from the oil as the pressure of the well decreases during production. Also affecting the flow is the expansion of free gas or "gas cap," the influx of natural water, and gravity. Eventually, the natural pressure lowers to a point at which added pressure must be applied to the well to produce significant amounts of oil and gas.

  Many oil wells do not have a formation pressure high enough to push the head of oil standing in the well to the surface. In these cases, some artificial method for lifting the oil must be installed. The most common installation involves a motor and "walking beam" (like a seesaw) on the surface that operates the pump on the bottom of the production string. A chain of solid metal rods connects the beam and the pump. Another method, called gas lift, uses the buoyancy of a bubble of gas in the tubing to push the oil to the surface. A third type of artificial lift forces some of the produced oil down the well at high pressure to operate a pump at the bottom of the well. Even though initially an oil field may have enough pressure to produce naturally, artificial lift will usually be required in later stages of production. Gas wells that produce little or no liquid do not need artificial lift devices (see Figures I-4 and I-5).

ARTIFICIAL LIFT

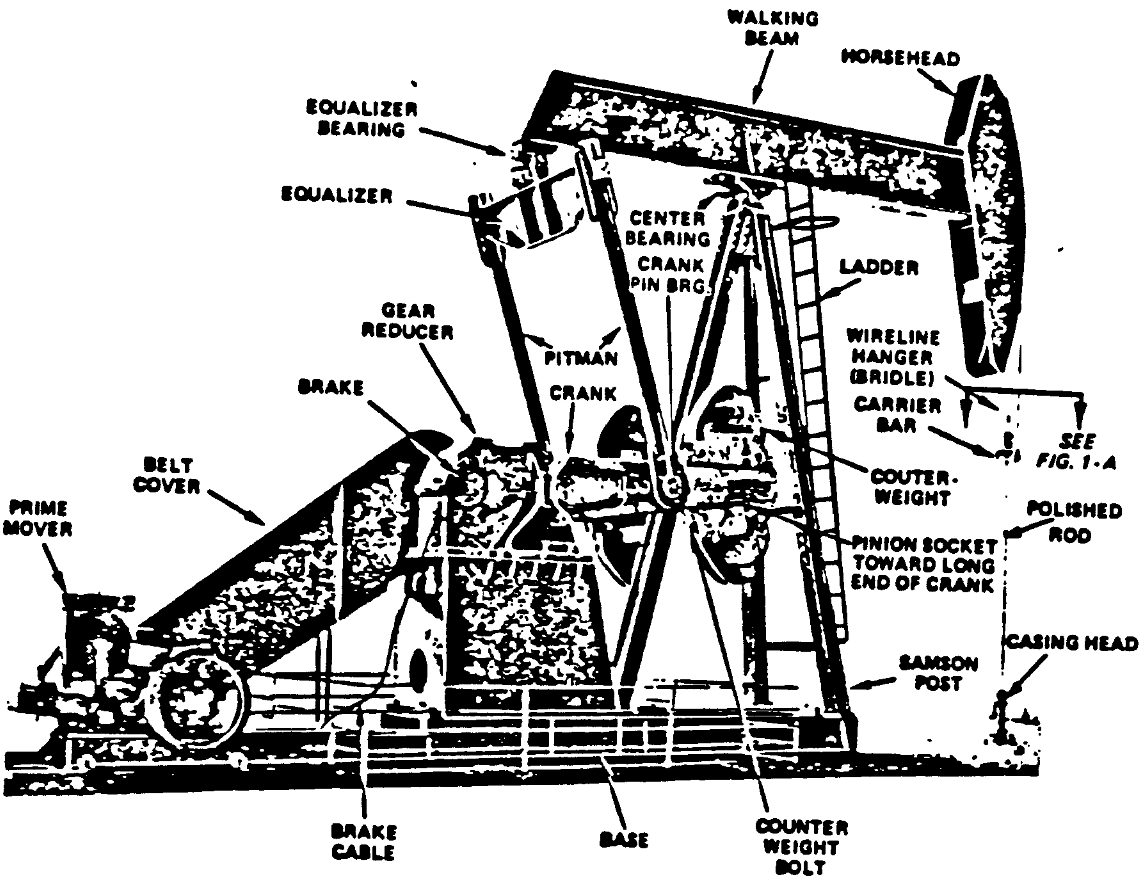
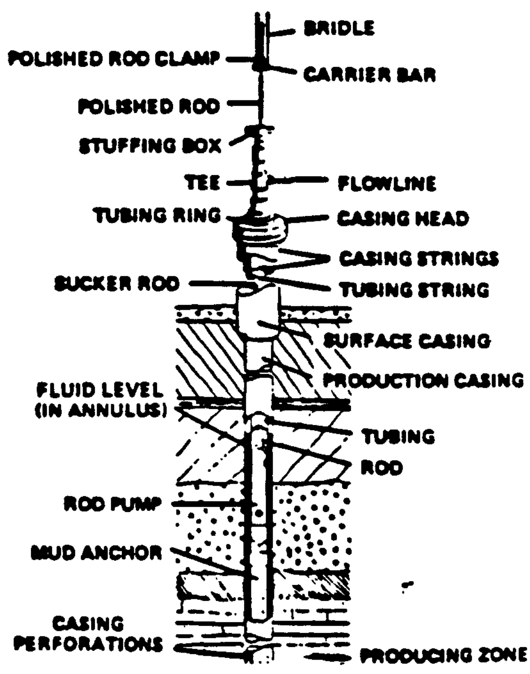


Figure I-4. The major parts of a conventional crank counterbalanced beam pumping unit are shown in this drawing. All units are not exactly like this one, but they operate generally in the same way.



Source: API. 1983. Introduction to Oil and Gas Production. Book 1 of Vocational Training Series, Pp. 8, 19.

Figure I-5. This sketch shows the principal items of wellhead and downhole equipment installed for a typical sucker rod pumping system.

- Secondary oil and gas recovery. Secondary oil recovery involves the injection of gas or water into the petroleum-bearing formation around producing wells. The injected fluids maintain reservoir pressure and displace a portion of the remaining crude oil to the production wells (see Figure I-6).

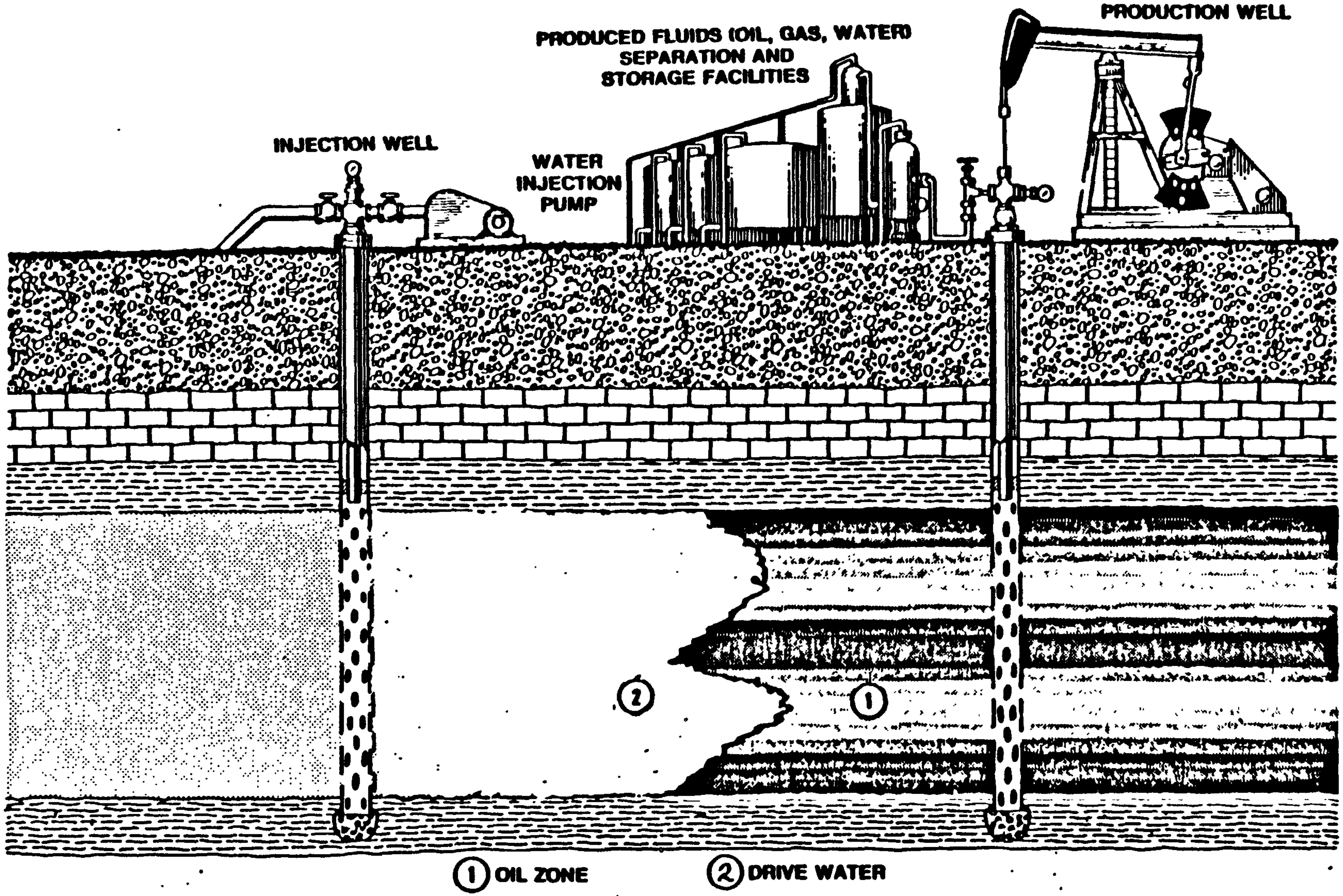
  Water flooding is the leading secondary recovery method and accounts for a very large part of all U.S. oil production. Fresh water or treated produced water is usually used as the flooding liquid. The use of natural gas for secondary recovery is limited because of its cost. Natural gas has a high market value and would only be used when water is not available.

- Tertiary oil and gas recovery. Tertiary (or enhanced) oil recovery is the recovery of the very last segment of oil that can be economically produced from the petroleum reservoir over and above what has already been economically recovered by conventional primary and secondary methods. Tertiary recovery operations generate wastes similar to other oil and gas field operations. Tertiary recovery can be divided into the following techniques or methods: chemical, miscible, and thermal. All of these methods involve injection of a solution or gas into the rock formation to direct the crude oil to the well from which it is recovered (DOE, 1984).

  The chemical methods of enhanced recovery include polymer flooding, surfactant flooding, and alkaline flooding. Each method is usually tied to a specific set of formation and crude oil conditions. Polymer flooding is simple and inexpensive; it is in fairly extensive commercial use. Surfactant flooding is expensive and still in the laboratory testing stages. Alkaline flooding fills a need in formations containing higher acid crude oils.

  Miscible oil recovery involves formation flooding with gases--carbon dioxide, nitrogen, or a hydrocarbon gas such as propane. The specific application of these techniques is the recovery of low viscosity crudes. Hydrocarbon flooding has been commercially available since the 1950s. Carbon dioxide and nitrogen flooding are more recent developments.

  Thermal recovery methods include steam injection and in situ combustion ("fire flooding"). Steam processes are most often applied to formations containing viscous crudes and tars. In situ combustion remains a terminal recovery technique because it burns out the hydrocarbons as the firefront advances through the formation. However, in situ combustion can yield up to 4 barrels of crude for each barrel burned.



SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Figure I-6

Workover Operations. As a well continues to produce crude oil and/or natural gas, its production may begin to decrease and may even cease. There are many geological and man-made reasons for this nonproductivity. Workover operations are operations on a producing well to restore or increase production. Producing wells need a workover operation when there has been a mechanical failure or a blockage from corrosion products or sand.

A typical workover cleans out a well that has sanded up. The tubing is pulled, the casing and bottom of the hole are washed out with mud, and, in some cases, explosives are set off in the hole to dislodge the silt and sand (Williams and Meyers, 1984).

Workover operations generate cleaning fluids, packing fluids, bailing fluids, and deck drainage that must be disposed of.

Well Stimulation Techniques. The well stimulation techniques discussed in the Industry Profile, Exploration and Development Operations, and Well Stimulation sections, are equally applicable to production well enhancement. Well stimulation wastes may include acids, additives, and other wastes as discussed above.

Surface Production Operations

Surface production operations generally include transport of the well fluids (oil, gas, gas liquids, water) from the wellhead or from a group of wells to a facility that separates the fluids and treats them prior to sale. The separation facility is called a lease operating unit, or tank battery (see Figure I-7). Products may be transported from the tank battery by truck or pipeline.

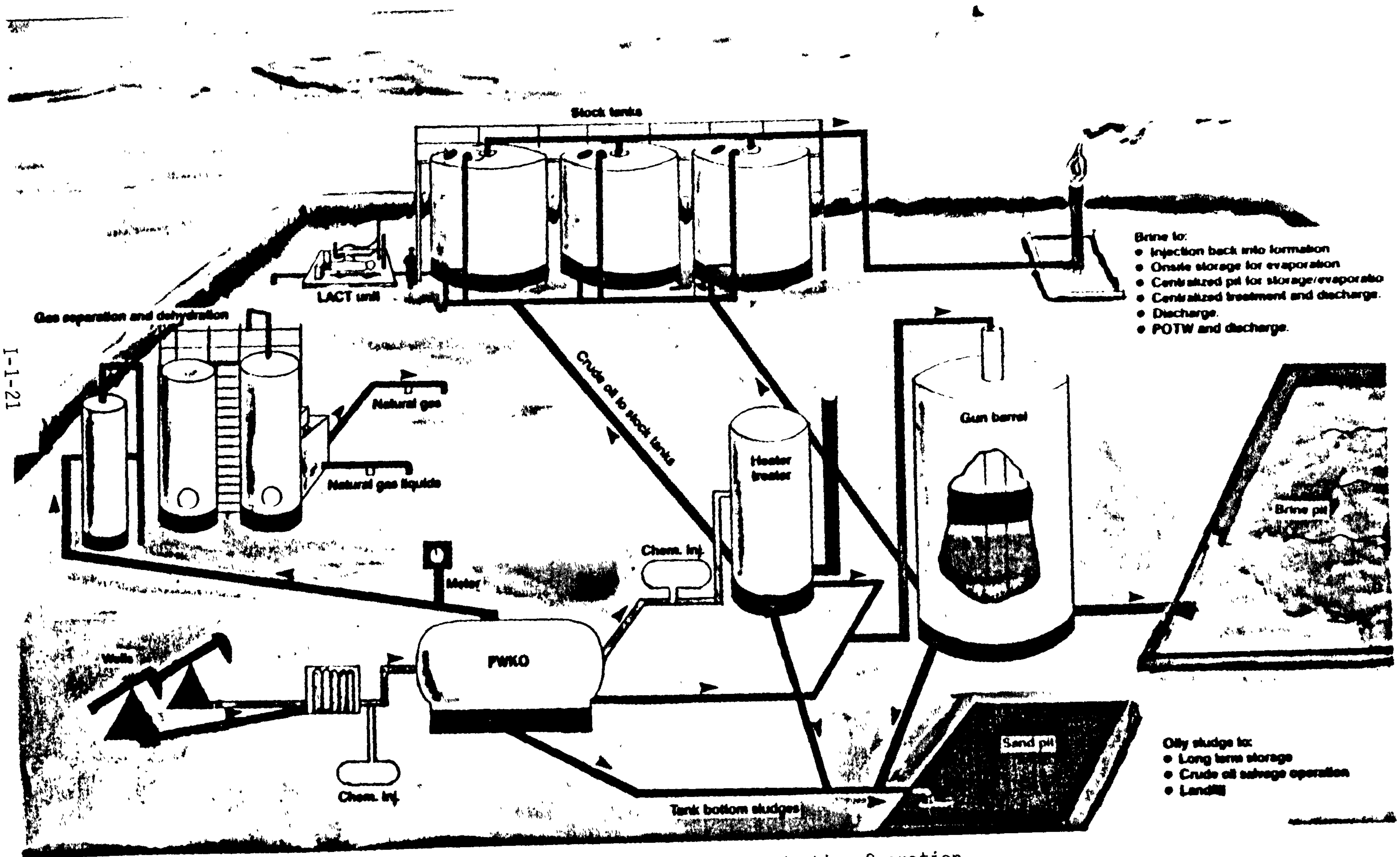


Figure I-7 Oil/Gas Production Operation

Impoundments (or pits) are used in nearly all petroleum producing operations to contain produced water and other waste material generated at the production site.

For clarity, the following discussion of production processes will focus separately on oil and gas and will briefly consider the case where gas production is concomitant with oil production. The first example to be discussed is production of oil.

Oil Production Operations. Water, oil, oil/water emulsion, and limited amounts of gas flow into the well and are brought to the wellhead. This mixture is usually piped from the wellhead, through an oilfield gathering system serving many wells, to the lease operating unit or tank battery, although some wells have dedicated surface facilities (see Figure I-7).

A "separator" may be used to divorce produced gas from produced fluids (including oil and water at this point). A separator is a vertical or horizontal baffled vessel; it is designed for sufficient retention time to allow gas to break out of the wellhead fluids. If the quantity of gas is low, a "free water knock out" vessel may be used to make the initial separation of free water (taken off the bottom of the vessel) and gas (taken off the top of the vessel) from free oil and oil emulsion (taken from the midsection of the vessel) (see Figure I-7). Gas from the separator and/or the free water knock out may be routed into a low pressure gas gathering system or flared (burned in a controlled manner onsite). Produced water is sent to an impoundment, pit, or tank to accumulate prior to disposal.

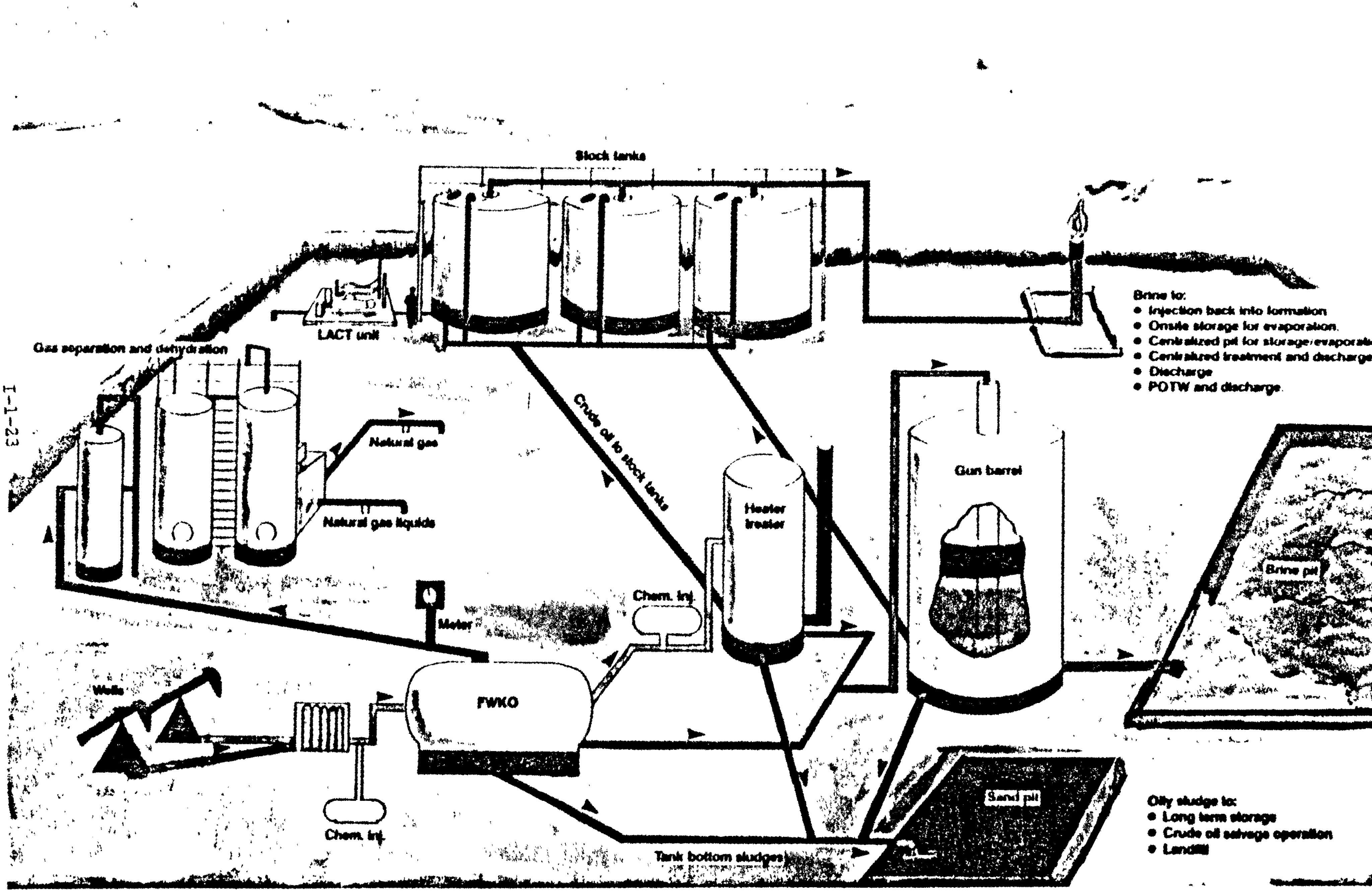


Figure I-7: Oil/Gas Production Operation

The free oil and oil emulsion may be treated differently from site to site, depending upon how difficult it is to break the emulsion and other factors. If the emulsion is difficult to break, the free oil and oil emulsion may be heated and chemically treated prior to mechanical or gravity separation. A "heater-treater" is used to heat the free oil and oil emulsion prior to a settling process (see Figure I-7).

If the emulsion can be broken through longer settling time (with or without emulsion-breaking chemical addition), the free oil and oil emulsion are sent to a larger settling vessel, usually a "gun barrel" (see Figure I-7). The gun barrel may be used as the settling vessel after the heater-treater, or it may be used alone.

Crude oil flows from the gun barrel to stock tank(s) (see Figure I-7). Ownership of the oil may change past the stock tank. Stock tank oil is measured (corrected to 60°F) and moved off the lease or unit for sale.

The most modern production sites have computerized oil transfer gauging systems called Lease Automatic Custody Transfer (LACT) units. These units take samples, record temperature, and determine the quality and net volume of the oil. They also recirculate bad oil for reprocessing, keep records for production and accounting purposes, and shut down and sound an alarm when something goes wrong. LACT units are used mainly with pipeline systems.

In all crude oil recovery methods, aqueous solutions are produced and must be treated, stored, recycled, or disposed of. As a well ages, the aqueous fraction of the crude oil-water production increases. In California, there are areas where crude oil wells produce 98-99 percent brine with 1 to 2 percent crude oil. For stripper well production, 25 to 80 percent is brine (EPA, 1986).

Depending upon State regulations, produced water may be reinjected into the petroleum formation, used for ice control or as a dust suppressant on roads, land spread, stored in pits to evaporate, percolated, or be discharged into surface waters.

Gas Production Operations. As in oil production, water, liquid hydrocarbons, and impurities must be removed from natural gas before it can be marketed. Gas production contains limited amounts of heavier petroleum compounds. Gas is separated from wellhead fluids in a separator.

In one technique, natural gas from the well enters a chamber where the pressure on the gas is increased. This causes a concomitant decrease in temperature, and petroleum liquids and water precipitate out of the gas stream and flow through a drain at the chamber bottom. Natural gas exists near the top of the chamber. Heat exchangers are also used with this system to further cool the gas. This process is also called Low Temperature Separation. In this system, the petroleum liquid that settles out of the separator bottoms enters a low pressure separator chamber where additional gas is removed. Natural gas and petroleum liquids are the products that leave this separator (API, 1976). This gas may still contain substantial amounts of water. It must be dehydrated and sold, or sent to a gas plant for further processing.

One problem associated with the production of natural gas is the presence of free water. Free water promotes corrosion and formation of hydrates. Both corrosion and hydrates cause increased piping pressure drops and piping restrictions. Hydrates are precipitates that form in the presence of free water under certain conditions. The greater the pressure in the equipment, the higher the temperature at which hydrates will form. Hydrates will form of methane, ethane, propane, isobutane, normal butane, hydrogen sulfide, and carbon dioxide from a natural gas stream (API, 1976).

Problems associated with the presence of free water may be avoided by dehydrating the gas stream or by preventing formation of hydrates in other ways. Water may be removed by glycol dehydration, by desiccants, or by expansion-refrigeration. Glycol is a liquid desiccant that absorbs water from the gas. When using liquid absorbent, the gas passes through a chamber into which a fine spray of the liquid is introduced. The liquid flows out the bottom of the chamber and is heated to remove the water so that the liquid can be reused. The dry gas exits the chamber at the top. Solid absorbents (desiccants) are used in conjunction with a gas permeable filter through which the gas flows. The solid absorbent may be renewed by heating (API, 1976).

Hydrates usually are prevented or removed from the gas stream by one of three methods. The first method is to remove the water, and various ways of doing this have been described. Another method is to heat the gas stream to keep the hydrate from becoming saturated in the gas. When using the latter method, heating has to be repeated at every point where hydrate formation is likely. The third method of hydrate control is to add a chemical to the gas stream to lower the temperature at which the hydrate will precipitate (i.e., "antifreeze agent"). Alcohol is usually used for this. With the hydrogen sulfide hydrate, a solid filter can be used to remove the hydrate. As the gas stream containing hydrogen sulfide passes through this filter, the gaseous hydrogen sulfide is converted to solid iron sulfide (API, 1976). These filters cannot be reused and must be properly disposed of.

Once removed, free water may be accumulated in tanks, pits, or impondments pending disposal.

Other impurities, such as hydrogen sulfide and carbon dioxide, must also be removed from the gas stream. The removal processes vary from absorption to chemical reaction. All of these removal processes generate waste material.

Produced water disposal is described in the previous section, Oil Production Operations.

WASTE GENERATION

This section identifies the sources of wastes considered within the scope of this study and presents a methodology, or the means by which EPA will develop the methodology, for generating national estimates of volumes for major wastes (i.e., drilling fluids, well stimulation and well completion fluids, workover fluids, produced fluids). In addition, a brief literature review is presented. Quantitative estimates of waste volumes will be completed for inclusion in the final Report to Congress.

The methodologies presented herein have inherent limitations. Some of these limitations include:

- Oversimplification;
- Incomplete accounting of wastes generated (i.e., accounts for drilling media but not other associated wastes such as well treatment/well completion fluids, deck drainage, sewage, etc.);
- Lack of accounting for drill cuttings and formation fluid; and
- Lack of accounting for drilling media makeup water.

Nevertheless, these limitations do not preclude the Agency from calculating estimates of waste volumes. The Agency plans to use the method(s) presented herein (or combinations thereof) to estimate waste volumes. Waste volume estimates will be used in the risk assessment and economic analysis (see Part IV, Risk Assessment).

For this preliminary technical report, the potential wastes generated from oil and gas exploration, development, and production activities are listed in Table I-2. Not all of these wastes are necessarily within the scope of the project as discussed in the Introduction.

Literature Review

EPA has conducted an extensive literature review of both published and unpublished reports addressing the sources and volumes of wastes generated from the exploration, development, and production activities of oil and natural gas. One aspect of this process was a review of EPA's literature in this area. This includes the EPA 1976 Oil and Gas Extraction Industry Development Document for the Office of Water's effluent limitations guidelines (See Appendix A - EPA) and the 1985 Proposed Development Document for the offshore segment of the oil and gas extraction industry effluent limitations guideline.

The disposal of wastes associated with oil and gas drilling and production has been an increasing concern over the last five years. As a result, the main objective of most of the literature has been to evaluate disposal practices of the given waste in a given area of reporting, or to present case studies. Therefore, any reporting of volumes of waste has been a minor objective, if performed at all (Waite et al, 1983; Eck and Sack, 1984; Elmer E. Templeton and Associates, 1980).

A. Exploration/Development

1. Drilling media

   a. Water-base drilling fluid system
   b. Oil-base drilling fluid system
   c. Pneumatic drilling fluids system
      - Air
      - Foam
      - Mist
      - Aerated mud
   d. (Some) produced fluids

2. Drill cuttings

3. Deck drainage

4. Well completion fluids/well treatment fluids

5. Well Stimulation fluids

6. Packing fluids

7. Waste lubricants, waste hydraulic fluids, waste solvents, and waste paints

8. Sanitary Waste

B. Production

1. Produced waters (oil and gas)
   - Skimmed solids from air flotation units
2. Produced sand
3. Workover fluids
   - Cleaning fluids
   - Packing fluids
   - Bailing fluids
   - Deck drainage

4. Field tank bottoms
   - Gun barrel
   - Free water knockout (FWKO)
   - Stock tank(s)
   - Other production tanks
   - Skimming surface impoundments, pits, and tanks

5. Waste crude oil

6. Waste specialty chemicals, waste lubricants, waste hydraulic fluid, waste motor oil, waste paints; waste solvents

7. Sanitary Waste

8. Waste associated gases (CH_4 & H_2S)

9. Waste triethylene glycol (TEG)

10. Gathering pipelines to central oil and gas separation facilities
    - Hydrostatic test fluids
    - Pig wax
    - Filters/slug catchers

11. Secondary and tertiary production operations
    - Produced water
    - Tank bottoms [all sorts - be more specific]
    - Filter media (solid waste)
    - Water treating residues
    - Pipeline pigging waters (prior to separation facilities)
    - Workover fluids
    - Waste fluids from compressors, turbines, and boilers
    - Waste paints, waste solvents, waste specialty chemicals
    - Waste associated gases
    - Waste crude oil
    - Dehydration units (waste TEG)
    - Waste scrubber sludges
    - Sanitary Waste

Table I-2: List of Potential Wastes

Many of the reports collected address a single waste such as drilling fluids (Canter, et al., 1984; Freeman and Deuel, 1986; West and Snyder-Conn, 1985), pit fluids (EPA, 1984), drill cuttings (Michigan Oil and Gas Association, 1984), or produced waters (Elmer E. Templeton and Associates, 1980; Morton, 1983; Herrold, 1984; Coleman and Crandall, 1981). Some documents attempt to discuss both drilling fluids and produced waters (Waite et al., 1983; EPA, 1985a; EPA, 1985b; API, 1983). Few studies attempt to address other oil and gas "associated wastes" (Waite et al., 1983).

Almost all of the literature is either site-specific (Heitman, 1985; Manuel, 1982; CH_2M Hill, 1983), State-specific (Morton, 1984; Birge et al., 1985), or regionally-specific (Murphy and Kehew, 1984; Alaska DEC, 1983; Freeman and Deuel, 1986; Powder River Conservation District, 1986). None of the literature addresses the wastes generated from the oil and gas extraction industry from a national perspective. Data reporting volumes for the two main wastes, drilling fluids and produced water, are periodically presented (Waite et al., 1983; Eck and Sack, 1984; Wilkerson, 1984; Rafferty, 1985). Of all the wastes generated, produced water figures are reported with the most frequency, followed by drilling fluids. There are many reports that address the waste and/or disposal practice without waste volumes reported (API, 1983; Freeman and Deuel, 1986; Canter et al., 1984).

Two major problems exist with most of data presented. One problem is verification of the source. For example, Rafferty (1985) stated that an estimated 315 million barrels of waste drilling fluid are generated by onshore oil and gas drilling activities. There is no supporting documentation to verify that number, however. The second problem is determining how to evaluate data when they are derived using different approaches.

For example, EPA has received two recent submittals addressing West Virginia brine production. In 1984, Eck and Sack estimated West Virginia brine production at 11.6 million barrels annually. In 1986, the West Virginia Oil and Natural Gas Association and the Independent Oil and Gas Association of West Virginia (hereafter "West Virginia Joint Survey") submitted profiles of average brine production for over 5,000 wells in West Virginia. The methodology and documentation of both estimates are illustrative of the difficulties encountered when evaluating previous waste volume estimates.

Eck and Sack based their estimate on information from a variety of sources and on assumptions. The number of producing oil and gas wells for 1981 was obtained from the Interstate Oil Compact Commission (IOCC, 1982). Estimates of brine production per well were obtained from a report on produced water volumes in two districts of Pennsylvania (Waite, et al., 1983). As shown in Table I-3, Waite, et al., presented only ranges of produced fluids observed from a few specific Pennsylvania areas. Eck and Sack apparently assumed that the average of the product water volumes paralleled West Virginia brine production. This is a major assumption that overlooks the effects of the different geologies of Pennsylvania and West Virginia, the relative ages of wells (i.e., older wells produce more water), and local production practices. In addition, the format of the Waite, et al., production estimates was presented in terms of "deep gas wells," "shallow gas wells," and so on. This situation appears to have compelled Eck and Sack to assume ratios of "deep gas wells," "shallow gas wells," and so forth in West Virginia for purposes of estimating volumes. Table I-4 presents some of the assumptions and calculations of produced water in West Virginia.

The 1986 West Virginia Joint Survey used a different approach to illustrate brine production ranges in that State. A survey was conducted

TABLE I-3

ESTIMATED WASTE FLUID VOLUMES IN PENNSYLVANIA

Development Areas	Waste Fluid Type	Ranges In Waste Fluid Volumes Per Well
I. Shallow Oil	Fluids Produced During Drilling	* 0-2,000 Gal.
	Stimulation Fluids	26,000 Gal.
1A. Venango District	Production Fluids (After 6 months of pumping)	1-2 BBL/Day (42-84 Gal/Day)
1B. Bradford District	Fluids Produced During Drilling	* 0-2,000 Gal.
	Stimulation Fluids	30,000 Gal.
	Production Fluids (After 6 months of pumping)	1-2 BBL/Day (42-84 Gal/Day)
II. Shallow Gas	Fluids Produced During Drilling	* 0-5,000 Gal.
	Stimulation Fluids	40,000 Gal.
Upper Dev.	Production Fluids	0-1 BBL/Day (0-42 Gal/Day)
III. Deep Gas	Fluids Produced During Drilling	* 0-25,200 Gal.
	Stimulation Fluids	58,800 Gal.
Medina Fm.	Production Fluids	2-4 BBL/Day (84-168 Gal/Day)

* Estimated volumes of fluids produced during drilling, does not include top hole water or ground water encountered before surface pipe is set.

These estimates apply only to air rotary drilled holes.

All ranges are considered typical for the type of well indicated. Individual wells or groups of wells in selected locations may differ significantly from the ranges indicated here.

Source: Waite, B.A., Beauvelt, S.C., and Mood, J.L., 1983, Oil and Gas Well Pollution Abatement Project ME No. 81493, Part C. Moody and Associates, Inc. Meadeville, Pa. Pg. 53

TABLE I-4

ESTIMATE OF BRINE PRODUCTION IN WEST VIRGINIA

Assumptions:

- o Daily volumes of brine produced per:

  Deep gas well - 2 BBL/day
  Shallow gas well - 0.35 BBL/day
  Shallow gas well - 1.2 BBL/day

  (Above values chosen from Table I-3)

- o 90% of Gas wells are "shallow"
  10% of Gas wells are "deep"
  100% of Oil wells are "shallow"

Given:

- o No. of producing wells in West Virginia in 1981:

  Gas wells - 26,925 Oil wells - 14,700

Calculate daily brine production per gas well based on above information:

(0.90 x 0.35 BBL/day) + (0.10 x 2 BBL/day) = 0.52 BBL/day

Calculate annual brine production:

- o Gas wells:

  0.52 BBL brine/day/well x 26,925 wells x 365 days/yr

  = 5,110,365 BBL brine/year

- o Oil wells:

  1.2 BBL brine/day/well x 14,700 wells x 365 days/yr

  = 6,438,600 BBL brine/year

- o Total produced brine:

  5,110,365 BBL brine from gas wells/yr

  + 6,438,600 BBL brine from oil wells/yr

  = 11,548,965 BBL brine/yr

  = 11.6 x 10^6 BBL brine/yr

Source: Eck, Ronald W. and William A. Sack. 1984. "Determining Feasibility of West Virginia Oil and Gas Field Brines as Highway Deicing Agents, Phase I, Volume II - Appendices." WVDOH Research Project 68. West Virginia Department of Highways in cooperation with U.S. Department of Transportation and Federal Highway Administration.

of 5,232 wells in West Virginia, and the results are presented in Table I-5. The results are informative but not concrete. In fact, major assumptions would still be required to project West Virginia production from Table I-5.

An interesting comparison of the Eck and Sack and West Virginia Joint Survey results is possible by back-calculating total estimated brine production (on a per-well basis) from Eck and Sack as follows:

Given: Total estimated brine production = 11.6×10^6 BBL/yr

Calculate: Unit brine production for:

- Gas wells: $\dfrac{5.1 \times 10^6 \text{ BBL brine/yr}}{161{,}251 \text{ MMCF gas/yr}}$

  = 31.6 BBL brine/MMCF gas

- Oil wells: $\dfrac{6.4 \times 10^6 \text{ BBL brine/yr}}{2.433 \times 10^6 \text{ BBL oil/yr}}$

  = 2.63 BBL brine/BBL oil

These results are not inconsistent with the results of the West Virginia Joint Survey presented in Table I-5. These examples were not selected to say whether one number calculated is potentially better than the other, but to illustrate how carefully numbers presented in the literature for any waste will have to be evaluated.

Exploration and Development Wastes

As shown in Table I-2, wastes associated with exploration and development are largely drilling media (the media used to drill, i.e.,

TABLE I-5

WEST VIRGINIA PRODUCED WATER SURVEY

2,799 Gas Wells

Gas Vol. MCFPD	No Prod. Water	0-10 BPM[1] Prod. Water	10-20 BPM Prod. Water	20-30 BPM Prod. Water	30-100 BPM Prod. Water	>100 BPM Prod. Water	Total	% of Total
0-10	676	143	5	0	0	1	825	30%
10-30	423	663	31	32	3	0	1,152	41%
30-60	275	182	21	47	22	11	558	20%
>60	91	137	24	4	5	3	264	9%
TOTAL	1,465	1,125	81	83	30	15	2,799	
% of TOTAL	52%	40%	3%	3%	1%	1%		

2,453 Oil Wells[2]

Oil Vol. BOPD	No Prod. Water	0-10 BPM Prod. Water	10-20 BPM Prod. Water	20-30 BPM Prod. Water	30-100 BPM Prod. Water	>100 BPM Prod. Water	Total	% of Total
0-1	447	491	121	64	130	404	1,657	63%
1-5	283	62	28	20	63	305	761	31%
5-10	19	3	0	2	2	1	27	1%
>10	5	2	0	0	0	1	8	1%
TOTAL	754	558	149	86	195	711	2,453	
% of TOTAL	31%	23%	6%	3%	8%	29%		

[1] BPM is defined as Barrels Per Month
[2] Does not include any waterflood producing wells.

Source: Independent Oil and Gas Association of West Virginia and West Virginia Oil and Natural Gas Association. 1986. "Oil and Gas Produced Water Survey." Submitted to EPA April 30 .

fluids, air, gas), cuttings, and deck drainage. In general, these wastes are temporarily (up to 1 year) or permanently disposed of into an earthen pit, the reserve pit. Some long-term disposal options are: dewatering and burial, land farming, road spreading, and centralized pits (see Industry Waste Management Practices). Well completion and/or treatment fluids, along with well stimulation fluids, also may be disposed of into the reserve pit. Smaller volume wastes such as waste lubricants, hydraulic fluids, solvents, paints, and sewage may either be commingled in the reserve pit or disposed of separately, which can be subject to control by regulatory programs. At this time, volume estimates will not be developed for small miscellaneous waste sources; any incremental estimate of these waste volumes is not expected to significantly increase the overall volume estimate per well site for exploration and development sources. Also, EPA is still defining the scope of this project, which could affect the Agency's need to quantify volumes of wastes generated (see Introduction).

Virtually every aspect of drilling operations affects the quantity of wastes generated. Table I-6 presents a listing of factors that can influence waste volumes. These factors may influence volumes individually, but they usually are so strongly interrelated that the effect of a single factor can be obscured.

For example, anticipated downhole geology dictates the drilling media selected. When water-bearing formations are encountered, however, waste volumes increase (via water displaced to the surface). Further, the addition of this connate water causes changes in the drilling media for which compensation is required. The addition of connate water also contributes to the possibility of such problems as stuck drill pipe. Once the drilling media and drill cuttings are brought to the surface, the type and extent of solids control equipment used influence how well the cuttings can be separated from the drilling fluid, and hence also

TABLE I-6

FACTORS INFLUENCING THE VOLUME OF WASTE

DRILLING FLUIDS, DRILL CUTTINGS, WELL TREATMENT/WELL COMPLETION,

- Geology, e.g.
  - Hard rock formations
  - Shale
  - Sandstone
- Well Depth / Hole Size / Casing Program
- Drilling media; e.g.
  - Mud type
  - Air
  - Gas
  - Foam
- Extent of solids control equipment used; e.g.
  - Influences the amount of water added to the circulating mud system
  - Cuttings washing efficiency
- Problems encountered during the operation; e.g.
  - Stuck pipe
  - Lost circulation
  - High pressures and temperatures (expected/unexpected)
- Service products used; e.g.
  - Types of products used
  - Numbers of products used
  - Solids vs. liquids

influence the volume of waste displaced to the reserve pit. When poor drill media/cuttings separation occurs, the drill media must be continuously diluted with makeup water to counter the high solids content of the media. Thus, poor surface separation causes drill media volume swell. This example is illustrative of the interacting factors that affect final waste volume. All of the factors in Table I-6 are similarly complex.

Table I-7 describes factors affecting total solids content in weighted drilling muds. The table further illustrates the number and type of factors introducing variability into volume estimates. Even with these factors in mind, EPA will fulfill the larger objective of collecting pertinent information by examining the data collected through standard industry recordkeeping practices.

For example, drilling contractors keep records that routinely itemize the type and quantities of products used on a given well; this information is extremely site-specific. The drill report does not describe the solids control equipment in use at the site, however, nor does it include freshwater consumption data. The information noted on the drilling report is generally unavailable to the Agency because it is not required in State or Federal regulatory programs. Some drill report data were collected during the screening sampling program conducted in conjunction with this study during June - September 1986, and will be presented in the January 31, 1987, Technical Report.

Drilling Waste Methodology

EPA plans to work cooperatively with the Petroleum Equipment Suppliers Association (PESA) to develop a methodology to estimate drilling waste

Table I-7 Factors That Control Total Solids Content in Weighted Muds (Numbered in Order of Decreasing Influence)

Item	Contributes to low total solids	Contributes to high total solids
	First Order of Importance	
1a Type of formation	Medium hard Unconsolidated sand and gravel	Unconsolidated silt Very hard
1b Bit cutter type	Long teeth	All Small diamond / Slow drilling
2 Mud density	Minimum	Above minimum
3 Bit jet horsepower	Adequate	Inadequate
4 Annular lift	Adequate	Inadequate (rare if hole is near gauge size)
5 Rig shale shaker	Constant efficient operation	Bypassed
	Second Order of Importance	
6 Full-flow	Effectiveness varies with formation and bit type	Not applicable
7 Rig screen mesh	Fine*	Coarse*
8 Fine screen used to return to system part of the liquid, clays, and silts from hydrocyclone	Secondary separation does not further reduce solids	Variable increase in total solids content, but more than centrifuge salvage (see No. 10); no viscosity reduction
9 Removing directly from system a fraction of clay and liquid with centrifuge, while maintaining weight and volume	Varaible effect on total solids content, but good viscosity reduction	Primary separation cannot increase total solids content
10 Centrifuge used to return to system the liquid and clay from hydrocyclone underflow (see No.6)	Secondary separation cannot reduce solids content; not normally recommended on water-base weighted muds	Variable increase in total solids content, but less than screen salvage (see No. 8); no viscosity reduction

Table I-7. (Continued)

Item	Contributes to low total solids	Contributes to high total solids
11 Chemical treatment to prevent shale cuttings dispersion	Variable (but may help screen removal?)	Normally does not cause, but decreases viscosity to total-solids-content ratio
12 Chemical treatment to disperse shale to clay-size particles	Variable, but can help centrifuge removal of shale as clays	Normally does not cause, but increases viscosity to total-solids-content ratio

* Whether or not a finer screen will help noticeably in this primary separation depends upon the comparative size relation between the cuttings reaching the surface and the screen mesh, and whether or not the finer mesh can be maintained in proper operation. If a "fine" screen cannot operate properly at full flow, a coarser screen will maintain lower total solids content than a finer screen that is bypassed.

Source: Chilingarian, G.V. and P. Vozabute. 1983. Drilling and Drilling Finds. Elsevier Science Publishing Co., Amsterdam, Holland. pp. 450-451.

volumes generated annually. PESA is an industry trade organization that has a subset membership of drilling service and product supply companies. Members of PESA have substantial technical expertise in estimating drilling supply needs on a site-by-site basis. They also have considerable information on types and quantities of materials consumed.

Individual sources of wastes that will be considered in designing the methodology include drilling media, well completion treatment, and well stimulation fluids.

Some of the methodologies considered for estimating exploration and development wastes are:

- Determine the average well depth nationwide. Develop an estimate of the volume of drilling fluids used (either per foot or per the determined average well depth) based on site-specific or standard industrial calculations (Chilingarian, 1983). National volume would be estimated by multiplying the volume of drilling fluid used by the average number of wells drilled over the past three to five years.

- Interview and gather data from operators by State and/or by region. Extrapolate these data to the national level.

- Develop a model to consider all the possible variables or only the most important shown in Table I-6. This method has been rejected as a viable alternative because of complexity, number of variables, and the time and cost involved.

- The methodology (or combination of methodologies) used will be determined by the quantity and reliability of the data gathered.

Production Wastes

As shown on Table I-2, the main wastes associated with production activities are produced water, produced sand, workover fluids, tank bottom, waste crude oil, and waste triethylene glycol. Depending on the waste, the primary methods of disposal are injection into subsurface formations, deposition into earthen pits (production pits or impoundments), discharge to surface waters, and road spreading (see Industry Waste Management Practices). All of these methods are subject to control by existing State and Federal regulatory programs (see Appendix A). This technical report discusses the methodology used to estimate the volumes of produced water. Although EPA does not present a methodology for associated wastes generated from production activities, as discussed herein, the Agency is contemplating various courses of action to evaluate these wastes.

For example, while EPA recognizes that wastes are generated from secondary and tertiary enhanced recovery operations, the Agency will not include a methodology for estimating the volumes in this report. EPA is coordinating with the Department of Energy in this area in order to use the Department's expertise and existing data prior to generating any new estimates.

EPA has considered generating estimates of volumes of tank bottoms, waste crude oil, and waste triethylene glycol, but this technical report does not present such a method for several reasons. First, EPA found that the existing literature lacks any useful data. Second, the industry is not routinely submitting pertinent waste volume data to regulatory agencies because of the absence of such regulatory requirements. Third, there are many significant factors that can influence the volume produced (see Table I-8). At this time, EPA is considering the alternative of developing an industry profile and visiting commercial operations (that dispose of or reclaim these wastes) in various parts of the country to get an indication of the amount of waste tank bottoms or crude oil they routinely dispose of or reclaim.

TABLE I-8

FACTORS INFLUENCING VOLUMES OF WASTE

TANK BOTTOMS AND WASTE CRUDE OIL

- Type of crude oil, type of gas
- Single well vs. central battery vs. field separation facility
- Numbers, sizes, and types of vessels
- Method utilized for separation/dehydration - gravitational heater treater
- Age and efficiency of equipment used
- Settling time/velocity
- Any capacity for recirculating settled material, at what points, and how many times

As stated, EPA will estimate annual quantities of produced water. Table I-9 lists the major factors influencing the volumes of produced water. Even with all these variables, estimating produced water volumes is possible, since many States require that volumes be reported (Herrold, 1984b). The following methodology outlines how EPA expects to calculate volumes of produced water. EPA welcomes comments on this procedure.

Produced Water Methodology

The following method is proposed for use in determining a national estimate of volumes of produced water generated from primary, secondary, and tertiary oil and gas production operations:

1. Establish the number of producing oil and gas wells by State and by zone (EPA, 1986), as well as a total for the United States.

2. Establish a range of barrels of oil produced and the millions of cubic feet of natural gas and gas liquids produced by State, and a national total.

3. Complete and update a table similar to Table I-10 (Herrold, 1984b). The table will list which oil and gas States have any produced water reporting or manifest systems. Table I-11 presents an example from the State of Alaska (Alaska Oil and Gas Commission, 1986).

4. Review volumes reported in the literature (Elmer E. Templeton and Associates, 1986; Herrold, 1984a). Use estimates and/or water: oil/gas ratios presented in the EPA Eastern and Western Workshops Proceedings presented by State personnel where they can be verified (EPA, 1985a; EPA, 1985b). Review the data gathered during the screening/sampling program. This source of information will be valuable in those States where no formal reporting requirements exist and/or the data are not computerized.

5. Make use of regional oil and/or gas to water ratio patterns to estimate volumes for States where only hydrocarbon production information is available.

6. Make use of data from trade organizations (WVIOGA/O&NGA, 1986), research institutes, and/or other Federal agencies (such as the Department of Energy) when possible.

TABLE I-9

FACTORS INFLUENCING VOLUMES OF WASTE

PRODUCED WATER

- Type of producing well; e.g.,
  - Oil
  - Gas
  - Oil and gas
- Depth
- Type of reservoir; e.g.,
  - Light crude
  - Heavy crude
  - Wet gas
- Size of reservoir
- Age of the well; e.g.,
  - The older the well, the more associated water
- Water to product (oil, gas, oil and gas) ratio
- Type of production operation; e.g.,
  - Primary
  - Secondary
  - Tertiary

TABLE I-10

PRODUCED WATER RECORD-KEEPING IN
SELECTED STATES AND PROVINCES

	Production Records		Disposal Well Records		
	Annual	Monthly	Annual	Monthly	No Record
1. Texas	X				
3. California		X			
4. Louisiana			X		
5. Oklahoma			X		
6. Wyoming		X		X	
7. New Mexico		X		X	
8. Kansas			X		
9. North Dakota		X		X	
10. Mississippi		X		X	
11. Michigan	X				
12. Montana		X		X	
13. Colorado		X			
14. Illinois	X				
15. Florida		X			
19. Ohio					X
22. Indiana					X
23. Pennsylvania					X
24. West Virginia					X
27. New York	X				
Ontario	X			X	

Source: Herrold, Jeffrey E. 1984. Saltwater Disposal and Recordkeeping in Selected States and Provinces. Geological Survey Division, State Michigan. April 5. p. 6.

TABLE I-11

ALASKA PRODUCTION AND INJECTION SUMMARY BY ACTIVE FIELDS FOR MARCH, 1986

OIL FIELDS (ALL POOLS)	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	ADDL COMPS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK	11,056	15	9,770	2		3,210,415	17,678	1,320,091
GRANITE POINT	283,839	84,121	204,326	29		101,674,562	5,623,205	88,008,063
KUPARUK RIVER	8,615,161	1,976,567	11,317,013	290		222,934,126	58,839,044	263,269,481
MCARTHUR RIVER	711,412	1,851,671	397,229	64	8	508,418,938	188,211,424	187,275,045
MIDDLE GROUND SHOAL	279,221	413,197	180,472	44	2	147,879,226	64,846,856	74,815,940
PRUDHOE BAY	47,517,044*	9,912,945	89,114,326	545		4,498,842,867**	211,214,486	5,712,483,995
SWANSON RIVER	172,849	158,008	8,383,670	33		203,712,856	64,123,809	1,597,391,069
TRADING BAY	82,783	199,852	96,591	29	9	87,328,273	56,761,602	52,160,260
TOTAL ACTIVE FIELDS	57,673,365	14,596,376	109,703,397	1,036	19	5,774,001,263	649,638,104	7,983,724,744
DAILY AVERAGE	1,860,431	470,850	3,538,819	TOTAL INACTIVE		155,596	249	456
				TOTAL ALL FIELDS		5,774,156,859	649,638,353	7,983,725,200

NGL PRODUCTION	NGL (BBL)		CUM NGL (BBL)
KUPARUK RIVER	107,901		915,764
MCARTHUR RIVER	16,421		8,442,601
PRUDHOE BAY	7,454		1,966,069
SWANSON RIVER	3,121		1,130,065
TRADING BAY	196		356,765
TOTAL ACTIVE FIELDS	135,093		12,811,344
DAILY AVERAGE	4,357	TOTAL INACTIVE	0
		TOTAL ALL FIELDS	12,811,344

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	ADDL COMPS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK		4,971	1,566,090	4			73,591	34,320,925
BELUGA RIVER			2,246,507	13			810	210,806,294
EAST BARROW			60,106	4			109	2,949,047
KENAI		2,248	6,971,964	35	21	11,877	433,215	1,681,158,396
LEWIS RIVER		10	210,582	2			31	3,025,138
MCARTHUR RIVER			619,880	5				116,618,206
MIDDLE GROUND SHOAL			44,230	1				1,622,118
NORTH COOK INLET		1,010	3,933,501	12			77,854	744,477,620
SOUTH BARROW			64,453	6			12	16,798,646
TRADING BAY			14,720	1				2,423,066
TOTAL ACTIVE FIELDS		8,239	15,732,103	83	21	11,877	585,622	2,814,199,456
DAILY AVERAGE		265	507,487	TOTAL INACTIVE		0	0	18,089,167
				TOTAL ALL FIELDS		11,877	585,622	2,832,288,623

INJECTION PROJECTS	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	ADDL COMPS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
GRANITE POINT		683,613		20			121,399,398	
KUPARUK RIVER		14,201,612	9,132,506	163			112,178,863	216,721,825
MCARTHUR RIVER		1,191,948		7	1		834,736,981	63,034
MIDDLE GROUND SHOAL		619,160		19	1		246,366,122	
PRUDHOE BAY		38,102,031	81,032,023	125		13,012,875	775,934,095	5,172,121,249
SWANSON RIVER			8,113,868	8			8,471,561	1,813,955,984
TRADING BAY		13,803		1	1		120,990,437	
TOTAL ACTIVE FIELDS		54,812,167	98,278,397	343	3	13,012,875	2,220,077,457	7,202,862,092
DAILY AVERAGE		1,768,134	3,170,270	TOTAL INACTIVE		0	0	547,457
				TOTAL ALL FIELDS		13,012,875	2,220,077,457	7,203,409,549

*INCLUDES 1,570,347 BBLS OF CONDENSATE
**INCLUDES 74,209,475 BBLS OF CONDENSATE

Source: Alaska Oil and Gas Conservation Commission. 1986. The Alaska Report. May 28: Section IX, p. 1.

7. Assimilate produced water volume estimates by State, by zone, and nationwide.

8. Finally, cross-check these estimates by taking the oil and gas production figures generated by State, by zone, and nationally, then calculating a series of oil and/or gas to water ratios by zone, which are then weighted according to production figures to determine a national estimate.

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CHAPTER 2

INDUSTRY WASTE MANAGEMENT PRACTICES

INTRODUCTION

This section is a preliminary review of control and disposal techniques currently used by industry for wastes from onshore oil and gas exploration, development, and production operations. Descriptions are based on specific State or Federal regulatory requirements, published information, professional observations during screening sampling, and interviews. In addition, the practices described herein address the management of major waste streams (e.g., drill cuttings, drilling muds, produced fluids, etc.) identified in the previous section titled Waste Generation. This section will be expanded for the full Report to Congress.

Normally, in a technical review such as this, a discussion of "current" and "alternative" practices is presented. In the oil and gas industries, however, waste management practices are so varied (because of the influences of State and Federal regulations, operator preferences, etc.), that the terms "current" and "alternative" are often interchangeable depending on the context. Therefore, this section presents waste management practices without distinguishing their relative applicabilities. Technologies other than those presented in this review may be identified based on the analytical results of the EPA screening sampling efforts conducted from June through September 1986. These sampling efforts and associated results are briefly discussed in the section titled Evaluation of Waste Management Methods.

Although the disposal practices generally used by this industry are not highly complicated, they are fraught with variabilities that influence their ability to protect the environment. State agencies can accommodate these differences to a large extent by evaluating waste management practices for each individual case within a general regulatory framework. In some areas of a State, for instance, unlined reserve pits may be permitted.[1] In other, more hydrologically sensitive areas of the same State, reserve pits may be required to have liners (meeting permeability, puncture, and other durability specifications), monitoring wells, or a leak detection system. Thus, waste management practices (and the corresponding construction and monitoring requirements) are often tailored to the specific situation even within a particular State.

These variabilities and the lack of concrete data to characterize the extent of the practices prevent a definitive assessment of the relative effectiveness of disposal options at this time. The control and disposal techniques presented herein range from pilot operations to long-practiced methods, none of which have been verified by EPA for treatability or economic feasibility. Thus, it is the intent of this section to describe the general management practices employed for pertinent wastes. It is not the purpose of this section to quantify the number of sites using each waste management method or to address the effectiveness of disposal techniques.

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[1] In this report, the term "permitted" means that formal permits are issued by a regulatory agency for the practice described.

One difficulty encountered in developing this section is the widespread use of common descriptive terms for a variety of similar waste management practices. Where descriptive terms for waste management techniques varied, the most rational definition for purposes of this discussion was selected. The definition of these terms is clarified herein.

CURRENT INDUSTRY WASTE MANAGEMENT

Onsite Methods of Waste Disposal

The waste management methods discussed in the following sections are divided into four topics:

- Onsite Disposal of Pit Fluids;
- Onsite Disposal of Pit Sludge;
- Closed Systems; and
- Treatment and Discharge Options.

The first two topics are self-explanatory. The section titled Closed Systems discusses drilling mud recirculation systems and associated technology. The Treatment and Discharge Options section discusses two subcategories of the onshore segment of the oil and gas extraction industry effluent limitations guideline: (1) Agricultural and Wildlife Water Use and (2) Coastal Treatment and Disposal (see also Appendix A - EPA).

Onsite Disposal of Pit Fluids

Evaporation/Percolation Pits. Disposal of fluids by use of evaporation and percolation pits is the simplest and least expensive disposal method. It requires no special handling of the fluids and can often be achieved at the drilling site itself.

The purpose of an evaporation or percolation pit is to use the natural processes of liquid evaporation or diffusion through soil to remove liquids from waste drilling muds, cuttings, or brines. An evaporation pit may be lined or unlined. Percolation pits must, by definition, be unlined. Evaporation pits are widely used in areas of overall net evaporation or net evaporation seasons. Percolation pits are typically used in areas where there is no potential for ground-water contamination or when percolating fluids are known not to adversely degrade ground-water quality.

In many cases, the evaporation or percolation pit is the actual reserve pit on a drilling site. As drilling muds and other fluids are added to the pit, the evaporation and/or percolation of the liquids reduces the volume of the contents of the pit. Evaporation pits on drilling sites that use polymer muds are especially appropriate, since the dried residue of these muds often is very low in volume. At the conclusion of drilling activities, the reserve pit is allowed to be completely dewatered by one or both of the evaporation or percolation processes. This method of fluid disposal is preferred at sites in which the reserve pit is to be backfilled with the dried solid wastes remaining in the pit.

Evaporation pits and percolation pits can also be used for brine disposal. Percolation pits used for brine disposal are less common, since many States have regulations prohibiting such disposal. Some States allow such pits if the chloride content is such that no contamination would result if the fluids contacted ground water. Several States, such as North Dakota, and certain regions of New Mexico, do not allow the use of evaporation pits for brine disposal, except in emergency conditions. Reasons for prohibiting this form of brine disposal include the presence of shallow ground water, highly permeable soils, and/or inherently high chlorides concentrations in native brines. In general, the intent of regulations addressing brine disposal via evaporation or percolation is to protect ground-water quality.

Onsite Treatment and Disposal. Onsite treatment and disposal of reserve pit wastes is accomplished by a variety of techniques. The choice of treatment method depends on characteristics of the waste, economic considerations, and applicable State or Federal regulations.

Generally, most of the onsite treatment methods are designed to treat the wastes generated from drilling activities. The following sections titled Treatment and Discharge Options and Centralized Treatment Facilities discuss the disposal of other wastes such as produced water, completion fluids, and stimulation fluids.

Onsite treatment technologies are commercially available for reserve pit fluids as well as solids, typically in the form of mobile equipment brought to a drill site. Examples of liquid treatment methods are pH adjustment, aeration, coagulation and flocculation, centrifugation, dissolved gas flotation, and reverse osmosis. Chemical fixation or solidification is a method of pit solids treatment. Usually, a treatment company employs a combination of these methods in conjunction with physical separation techniques in order to treat the entire contents of a reserve pit. One possible treatment sequence is described as follows: A coagulant such as aluminum sulfate, ferric chloride, or calcium chloride is added to the pit followed by a flocculant (a natural or synthetic polymer) to remove suspended solids from the liquid phase. Depending on the results of this step, the liquid may be pumped from the pit and discharged to the land surface, or may receive further treatment in the form of centrifugation or filtration prior to final discharge. The pit solids are then stabilized by mixing in cement kiln dust, which produces a cement-like material that is buried onsite (see also Solidification).

Reverse osmosis has been used to treat reserve pit fluids. The process can be described in four steps:

- Preclarification in the pit by flocculation of suspended solids;
- Filtration of flocculated fluid down to particles of one micron in size (to extend the life of the membranes);
- Two-stage reverse osmosis through cellulose acetate membranes to reduce total dissolved solids; and
- Disposal of clarified fluid and concentrated fluid products (Moeco, 1984).

A unique alternative to flocculation and filtration of reserve pit waste is boiler-evaporation. A company that uses this technique states that it will treat "drilling fluids and drilling muds" from a reserve pit by steam-heating the wastes. Part of the process includes taking gas or oil from the wellhead onsite to burn in the boiler that provides steam to the evaporator (E-Vap Systems).

Many States allow onsite treatment and disposal of pit contents as an alternative to other, possibly less cost-effective means of disposal. Most States do not specifically require treatment of pit contents before they are buried or land-applied onsite, but treatment is often a necessary step in order to comply with limitations set on pollutant parameters for onsite disposal.

Among the States that address onsite treatment of pit contents, the most common limitations on pollutant parameters include pH, total dissolved solids, oil and grease, and metals such as arsenic, cadmium, chromium, lead, and mercury. For example, guidelines set by the West Virginia Department of Natural Resources for the acidic pit fluids from air drilling call for a pH between 8 and 10 for waste that is landspread "from oil and gas well operations." Other criteria required by West Virginia include a 24-hour waiting period between pH adjustment and discharge (for land application only), and reporting requirements to document the discharge. West Virginia also requires some laboratory analyses of pit waste samples in order to monitor compliance with the discharge limitations.

The type of method used for onsite treatment often depends on particular characteristics of a well site in addition to the pollutant parameters set by a State. For example, the only forms of pit treatment presently used in Alaska are "settling and freeze-thaw concentration of contaminants." That is, a pit must go through a one-year cycle of freezing and thawing, presumably to cause heavy metals to absorb permanently onto the drilling muds in the pit. The effectiveness of this technique is under debate within the State (EPA - AK, 1985b).

Finally, the choice of treatment method is influenced by the proximity of reserve pits (or production tanks) to centralized treatment/disposal facilities. Onsite waste treatment is often used in locations where centralized treatment/disposal facilities are excessively distant or not available. Centralized treatment and disposal practices are discussed in the section titled Centralized Methods of Waste Disposal.

Onsite Disposal of Pit Sludge

Pit Burial. Onsite burial of a pit is defined as the disposal of pit sludge and residuals within the approximate area of the pit. The solids are covered by backfilling and by pushing in the walls of the pit. This method of disposal is very often used for the closing of a dried evaporation/percolation pit.

In many States, onsite burial of closed reserve pits is the most common practice. Specific regulations for proper closure and burial vary from State to State. For example, time limits for closure vary. In Texas, the facility has 1 year after drilling ceases to close and bury the reserve pits. Oklahoma allows 18 months, while Louisiana allows only 6 months. Kansas has no time limit for reserve pit closure (EPA - KS, 1985b).

Some States require testing of pit contents prior to burial. Under Louisiana State Order 29-B, pit solids can be buried only if the following limitations are met:

Arsenic	10 ppm
Barium	2,000 ppm
Cadmium	10 ppm
Chromium	500 ppm
Lead	500 ppm

Mercury	10 ppm
Selenium	10 ppm
Silver	200 ppm
Zinc	500 ppm
pH	between 6 and 9
Oil and grease	3% weight
Moisture	50% weight
Conductivity	12 mmhos/cm

In addition, the buried mixture must be 5 feet below ground level and must be at least 5 feet above the water table.

Texas backfill requirements vary according to the type of pit and its chloride content. Permits may have pit closure requirements; however, the Texas Railroad Commission requires all pits to be backfilled and compacted for closure after dewatering.

Kansas encourages burial onsite, but has no law requiring backfilling of pits. In geologically sensitive or hydrogeologically sensitive areas, onsite disposal of drilling pit contents can be prohibited (EPA - KS, 1985b).

Wyoming pit closure rules are included in the drilling permits and may include special provisions such as testing and treatment prior to burial (EPA - WY, 1985b).

A modified version to standard pit burial is the method of encapsulation. This is a disposal method for burial of solids in a lined pit. After the pit is dried, the top of the pit is lined with plastic (presumably the same type of liner used on the pit bottom). The pit is then backfilled and compacted. In theory, the pit solids are completely separated from contact with other soil. This method is used to bury pits in Alaska, Michigan, and Utah.

Another modified method of pit burial is the technique of trenching. A synonym for trenching is spidering (Crabtree, 1985). Trenching is accomplished by pushing the pit solids into trenches extending out from the main body of the pit. This increases the load-bearing capacity, making it easier to cover the pit. It also tends to become structurally stronger over time. This practice was common in Michigan, but now has been phased out. It still is used in the Williston basin in North Dakota.

Solidification. Solidification of pit wastes is a method used to "stabilize" reserve pit wastes prior to pit closure. Problems reported by landowners, including reduced load-bearing capacity of the ground over the pit and the formation of wet spots over the pit, have prompted investigation into solidification. In addition, plastic pit liners that are now required in many States do not allow for timely drying of pit solids. Solidification provides a faster means of closing a pit, particularly in areas of net precipitation where seasonal changes often interfere with site restoration (Crabtree, 1985).

There are two categories in which solidification methods can be placed: chemical and physical. In general, chemical methods of solidification involve mixing cement-like products with the dewatered contents of a pit, and physical methods of solidification involve permanent freezing of pit solids. Only locations in Alaska have environmental conditions appropriate for physical solidification.

Solidification of pit wastes is offered as an acceptable disposal alternative in the regulations of several States. Title 18 of the Alaska Administrative Code, Chapter 60, specifically addresses construction requirements for "a containment structure which is designed to contain drilling wastes in a permanently frozen state," including a waste surface level 2 feet below the active thaw zone (18AAC 60.520, 1986). Louisiana's Statewide Order 29-B states that, "Pits containing nonhazardous oilfield wastes (as defined within Order 29-B) may be closed by solidifying waste and burying it onsite" if the material to be buried meets specified criteria, summarized in the table below:

- pH	6 - 12
- Leachate testing for:	
Oil and grease	$\leq$ 10.0 mg/l
Arsenic	$\leq$ 0.5 mg/l
Barium	$\leq$ 10.0 mg/l
Cadmium	$\leq$ 0.1 mg/l
Chromium	$\leq$ 0.5 mg/l
Lead	$\leq$ 0.5 mg/l
Mercury	$\leq$ 0.02 mg/l
Selenium	$\leq$ 0.1 mg/l
Silver	$\leq$ 0.5 mg/l
Zinc	$\leq$ 5.0 mg/l

- Top of buried mixture must be at least 5 feet below ground level and covered with 5 feet of native soil.

- Bottom of burial "cell" must be at least 5 feet above the seasonal high water table.

- Unconfined compressive strength	> 200 psi
- Permeability	$\leq 1 \times 10^{-6}$ cm/sec
- Wet/dry durability	> 10 cycles to failure

Michigan's Supervisor of Mineral Wells Instruction 1-84 specifies lined pit closure requirements, and includes the following statement regarding solidification:

> Earthen materials shall be mixed with the pit contents to stiffen it sufficiently to provide physical stability and support for the pit cover. A pit stiffening process as approved by the Supervisor may be used at the option of the operator.

Materials commonly used to "stiffen pits" in Michigan include native soils, gravel, and sawdust. Processes have been developed within the State that "stabilize" dewatered pit contents by addition of cement kiln dust, cement, and other materials. Mixing is performed by a backhoe or jet pump. The product of mixed waste and cement kiln dust resembles a low-grade mortar. The Michigan Department of Natural Resources has run tests on the raw material and the mixed product of one of three "stabilizing" processes used in the State, and has found that "addition of the raw material to a mud pit would not introduce toxic materials," among other findings. The Michigan DNR expressed concerns over elevated SO_4 levels found in leachate from the raw material, in addition to other findings, and is pursuing further investigations of pit stiffening materials (Crabtree, 1985).

A recent study conducted by scientists from Shell Development Company and the Environmental and Ground Water Institute investigated the behavior of drilling fluid wastes stabilized by the addition of fly ash. The study concluded that "no significant uptake or release of [heavy] metals can be expected during treatment," and that fly ash could be considered a valid method of treatment (Deeley and Canter, 1985).

Closed Systems

A closed system used for oil or gas drilling is a system in which the drilling fluids and liquids are recirculated and reused. A system in which the drilling fluids are partially recirculated represents a semi-closed system. The use of mud recirculation systems is a common practice for onshore drilling. Such systems can be closed or semi-closed. Their use represents a great benefit, as they can reduce the water and mud input requirements. This can translate into cost savings on raw materials and also a reduction of waste material generated requiring disposal at the conclusion of drilling activities.

Closed systems at drilling sites can be operated to have recirculation of the liquid phase, the solid phase, or both. In reality, there is no completely closed system for solids since cuttings are always produced and removed. The closed system for solids, or the mud recirculation system, can vary in design from site to site. However, the system must have sufficient solids handling equipment to effectively remove the cuttings from muds to be reused. A very common apparatus used for this purpose is the shale shaker. The shale shaker is essentially a screen that is used to separate cuttings from muds. Two types are common. In one type, the screen is in the form of a tapered cylinder that is rotated by the flow of the drilling fluid. The other is a rubber-mounted sloping flat screen that is vibrated by a motor; drilling fluids fall by gravity through the screen while the cuttings pass over the screen (McCray, 1959). Other equipment utilized for mud recirculation includes desanders, desilters, vacuum chambers (that can remove gas from the muds), and centrifuges.

Water that is removed from the mud along with the cuttings can be reused. A separate closed system for water reuse can be operated onsite along with the mud recirculation system. As with mud recirculation systems, the design of a water recirculation system can vary from site to site, depending on the quality of the recycled water required for further use. This may include chemical treatment of the water. Also, any solids must be removed from the water. This can be accomplished by the use of a centrifuge or similar apparatus.

A discovery well in France had, at the drilling site, a closed system for solids and liquids. The system combined physical and chemical water treatment with a conventional solids handling system to continuously create clean water. As a result, the total pit volume, treatment, and reserve was reduced to about one-third conventional volume (Neidhardt, 1985).

In the United States, onshore oil or gas drilling sites that have closed or semi-closed systems use variations of the systems described above. In California, one site was known to use a mud recirculation system using two shale shakers. The reduction of mud generated waste at this site was necessary as the wastes were stored in aboveground storage bins. At the conclusion of drilling, the contents of these bins were emptied and transported to a centralized treatment facility (EPA - CA, 1986).

In Michigan, a particular site used a mud recirculation system similar to the one observed in California. At this site, drilling wastes at the end of drilling were placed in a lined pit and were later removed by a vacuum truck (EPA - MI, 1986).

In Wyoming, mud recirculation systems were also used. At one particular site, two reserve pits were constructed. The first pit received all mud and cuttings from the well hole. The supernatant and mud flowed into the second pit, while coarse cuttings remained in the first. A large pipe was placed at the base of the second pit and thus recirculated only the mud from the second pit. The mud then went through an additional series of stages to further remove cuttings. At the conclusion of drilling, the pits were dewatered. The supernatant was removed for disposal at a disposal site; the solids remained in the pits and were buried (EPA - WY, 1986).

In Kansas, a different type of mud recirculation system was used. Mud and cuttings from the well hole were placed in a series of working pits. Mud flowed from one end of the working pit to the other. At the end of the pit, the mud was piped back to the well hole for reuse. As the mud flowed along the length of the working pit, the cuttings were removed by gravity settling. Pipes were placed at the base of the working pit, and at certain intervals the settled cuttings were removed and placed in the reserve pit. At the conclusion of drilling, the working and reserve pits were dewatered by evaporation and buried. Neither the working pits nor the reserve pits were lined (EPA - KS, 1986).

Treatment and Discharge Options

Agricultural and Wildlife Water Use. Agricultural and Wildlife Water Use is a subcategory under the onshore segment of the oil and gas extraction industry effluent limitations guideline. This subcategory, defined in 40 CFR Part 435, Subpart E, as authorized by the Clean Water Act, addresses the use of produced water that is of good enough quality to be used for livestock watering or other agricultural uses. This subcategory was formerly called the Beneficial Use subcategory. The terminology was changed because of the confusion resulting from the word "beneficial." The term "beneficial use" has a long history of use in Western U.S. water laws unrelated to its meaning in these regulations.

This subcategory was established because many western States had asked EPA to allow produced water to be discharged and used for agricultural and wildlife purposes. Investigation showed that in arid portions of the Western U.S., low-salinity produced waters were often a significant (if not the only) local source of water used for those purposes. The regulation is intended as a restrictive subcategorization based on the unique factors of prior usage in the region, arid conditions, and the existence of low-salinity potable water.

To qualify for the use of produced water under Agricultural and Wildlife use, the facility must be located west of the 98th meridian.

Also, to qualify, the facility must show that the discharged water will be used for agriculture or wildlife. The discharger must also meet the required oil and grease discharge limitation of 35 mg/l.

There are inconsistencies from State to State for the issuance of discharge permits under Agricultural and Wildlife Use. For example, 18 production facilities in Montana have been permitted, yielding a total daily discharge of 0.6 million gallons for agricultural and wildlife use (EPA - MT, 1985b). Wyoming currently allows discharge of produced water for agricultural and wildlife use under 550 NPDES permits with effluent limitations of:

TDS	5,000 mg/l
Sulfates	3,000 mg/l
Chlorides	2,000 mg/l
pH	6.5-8.5
Oil and grease	10 mg/l

(EPA - WY, 1985b).

These oil and grease limitations are met generally by the use of oil-water separation systems. In Wyoming, a system of pits connected in series has been used. Each pit is skimmed for removal of oil. The final pit discharges directly into the Powder River.

<u>Coastal Treatment and Disposal</u>. The framework for regulating treatment and disposal methods used in coastal areas is derived from the Coastal subcategory of the onshore segment of the oil and gas extraction industry effluent limitations guideline, defined in 40 CFR 435, Subpart D, as authorized by the Clean Water Act. The Coastal subcategory defines "coast" as "any body of water landward of the territorial seas, or any wetlands adjacent to such waters" (see also Appendix A - EPA).

Methods used for treatment and disposal of drilling or production wastes in coastal areas are based on State and Federal regulatory requirements. Where applicable, permits for discharge to coastal waters are written in accordance with the National Pollutant Discharge Elimination System (NPDES), and may be issued by State or Federal authorities. At this time, 37 States have approved State NPDES programs. In States that do not have approved NPDES programs, permitting of coastal discharges is coordinated through Regional EPA offices and State agencies concerned with these matters. States in EPA Region VI, for example, do not have approved NPDES programs.

Actual treatment and disposal methods in coastal areas depend on the nature of the effluent as well as applicable effluent limitations. Types of waste effluents permitted by Louisiana include produced water and water-based muds and cuttings (EPA - LA, 1985a). The Alaska Department of Environmental Conservation permits surface discharge of reserve pit fluids to the coastal tundra region, and specifically includes the following limitations in the permits:

pH	6.5 to 8.5	
Chemical oxygen demand	200	mg/l
Settleable solids	0.2	mg/l
Oil and grease	15	mg/l
Total aromatic hydrocarbons	10	ug/l
Arsenic	0.05	mg/l
Barium	1.0	mg/l
Cadmium	0.01	mg/l
Chromium	0.05	mg/l
Lead	0.05	mg/l
Mercury	0.002	mg/l

Frequently, the types of oil and gas field wastes that are permitted to be disposed of in coastal areas are expected to be compatible with the coastal environment, if kept segregated from unacceptable wastes. For example, at a production site in Louisiana, the contents of the produced brine are close enough to the State's tidewater effluent limitations that skim tanks to separate hydrocarbons from produced water are the only treatment used prior to discharge (EPA - LA, 1986). In most cases, monitoring, laboratory analyses, and reporting requirements are specified in permits for coastal discharges of any oil or gas field waste.

Simple separation techniques are not always sufficient to achieve required discharge limitations. In general, brine treatment technology is available in two categories: physical-chemical processes and biological processes. Examples of physical-chemical treatment include flotation, filtration, activated carbon adsorption, ion exchange, air stripping, and break point chlorination. Examples of biological treatment include dispersed growth systems such as aerated lagoons and activated sludge or fixed film systems such as trickling filters and bio-disks. The primary pollutants in produced water that these technologies affect include biological oxygen demand, chemical oxygen demand, phenols, ammonia, sulfide, and oil and grease. The most common method of treatment is oil removal, which can be accomplished in skim tanks, tube separators, and, more recently, sand filters. Biological treatment methods are only recently being considered as alternatives to more conventional techniques (Michalczyk, et al., 1984).

Centralized Methods of Waste Disposal

The waste management methods discussed in the following sections are divided into four topics:

- Centralized Pits;
- Centralized Treatment Facilities;
- Reconditioning/Recycling/Reuse; and
- Incineration.

The term "centralized," rather than "offsite," is used in this section to define a pit or facility designed, constructed, and operated expressly for the purpose of receiving wastes from numerous oil and/or gas field operations. The term "offsite pit" is used only in reference to such pits located in Oklahoma, because this term is in common usage there (Cantor, et al., 1984)

Centralized Pits

The use of centralized pits for disposal of oil and gas drilling and/or production wastes is practiced in several States. Centralized pits can be very large in size and can, as a result, accept the wastes for many well and production sites over large geographical areas. They can be designed to accept drilling muds, brines, or a combination of both. The design capacity of a centralized pit is directly related to land availability and topography, in addition to the anticipated volumes of drilling and production wastes generated in the "service area" of the pit.

The purpose of a centralized pit is to accept wastes from outside drilling and production activities and to provide long-term storage for these wastes. No treatment of the pit contents is performed. A properly sited, designed, constructed, and operated centralized pit allows the natural evaporation process to concentrate drilling fluids and brines. A pit is "closed" when it no longer receives any new material. The final disposition of the pit and its contents is determined by local or State regulations.

In Oklahoma, there are approximately 95 centralized pits (called "offsite pits" in the State), with surface areas as large as 15 acres and with depths up to 50 feet. They are created by excavating, damming gullies, and using abandoned strip pits. Rule 3-110.2 of the Oklahoma Corporation Commission permits centralized pits and their use provided that they are sealed with an impervious material, do not receive outside runoff water, and are filled and leveled within 1 year after closure. The chloride level of the pit contents cannot exceed 3,500 mg/l. The pits are periodically sampled and checked for chloride. If the contents are above the chloride limit, they must be treated and removed to a hazardous waste disposal site. Operators of new centralized pits are required to install and sample monitoring wells for chloride and pH. It is proposed to make this requirement applicable to existing centralized pits (Appendix A - OK).

In California, drilling fluids and brines may be transported to centralized pits. Drilling fluids are generally received by centralized evaporation sumps, but many of these sumps are also used for percolation where no freshwater source is near. No State manifest is required unless the material is classified by the State as hazardous. On the western side of the San Joaquin Valley, where ground water is of poor quality, there is a commercial facility on Federal land. At this facility, there are 20 to 40 acres of permitted sumps for evaporation and percolation. BLM has sumps on Federal leases that range up to 5 acres (Appendix A - CA).

In Ohio, the contents of reserve pits may be required to be removed and transported to an Ohio EPA (State) regulated disposal site. This is due to potential ground-water contamination from the pit. When pit contents are to be moved, the State requires tests to determine whether the waste can be disposed of in an approved landfill (Appendix A - OH).

In Texas, about 200 centralized saltwater disposal pits are in operation. These pits are regulated by the Texas Railroad Commission. State manifests are required to transport brines to these pits (Appendix A - TX).

In Wyoming, the Department of Environmental Quality regulates centralized pits. Such pits require operating permits from the State. To receive these permits, the pit operators must demonstrate that pit construction will not allow a discharge to ground water by direct or indirect discharge, percolation, or filtration. Also, it must be shown that the wastewater quality will not cause violation of any ground-water standards and that existing geology will not allow a discharge to ground water (Appendix A - WY).

Centralized Treatment Facilities

A centralized treatment facility for oil and gas drilling and production wastes is a process facility that accepts such wastes solely for the purpose of reconditioning and treating wastes to allow for discharge or final disposal. This removes the burden of required onsite treatment of wastes from the drilling or production facility. Centralized treatment can represent an economically viable alternative to onsite waste disposal. A treatment facility can be run in batch or continuous operation. The facility can have a design capacity large enough to accept a great quantity of wastes from many drilling and/or production facilities. In this way, the centralized treatment facility can treat a large quantity of wastes more efficiently than a single drilling or production facility can treat a small quantity of waste.

Many different treatment technologies can potentially be used in central treatment of oil and gas drilling and production wastes. The actual technology used at a particular facility would depend on a number of factors. One of these factors is type of waste. Presently, some facilities are designed to treat solids (muds and cutting), while others are designed to treat produced waters, completion and stimulation fluids, or other liquids. Some facilities can treat a combination of both. Other factors determining treatment technology include facility capacity, discharge options and requirements, solid waste disposal options, and other relevant State or local requirements.

Centralized treatment facilities can be divided into three different categories: drilling waste treatment, produced water treatment, and drilling waste and produced water treatment. Examples of each of these types are given below.

An example of a drilling waste treatment system is found in California. Drilling fluids at some drilling sites are accumulated in disposal bins. The contents of these bins are vacuumed into trucks and taken to a facility that uses a patented process to convert the sludge into a substance having a gel-like consistency that hardens in 2 hours. Metals within the drilling fluids are converted into stable, nonleachable metal silicates. The final product can be disposed of by landfill or can be used for backfilling or landfill covers (Ven Virotek, 1986). California regulations do not require a State manifest for transporting material unless it is determined to be hazardous under State regulations.

Another example of a central drilling waste treatment facility is in Alabama. The facility accepts water-based drilling fluids and sewage from offshore and coastal rigs in Alabama waters. Material is received by truck or by barge. From the holding container, the mud is pumped through shaker screens for cuttings removal. Treatment consists of pH adjustment, flocculation, clarification, and dewatering. The water is pumped to the local publicly owned treatment works (POTW) for final treatment. Solids are trucked off to the municipal landfill for disposal (SAFE, Inc., 1986).

Examples of brine treatment are exhibited in Pennsylvania and Colorado. Pennsylvania estimates that 20 percent of all brines are hauled to a treatment plant in that State (EPA - PA, 1985). It is the responsibility of the brine generator to transport the material to the treatment facility. Treatment at these facilities may include flow equalization, pH adjustment, settling and surface skimming, retention and settling, and aeration. These facilities must have NPDES and Pennsylvania Water Quality Management Part II permits. The permit criteria and limits will be governed by the receiving water quality standards. Generally, total suspended solids will be limited to an instantaneous maximum of 60 mg/l, with an average monthly of 30 mg/l. Oil and grease will have a maximum of 30 mg/l and an average of 15 mg/l. pH must be between 6 and 9 and dissolved iron will have a maximum of 7 mg/l (Appendix A - PA).

In Colorado, the State Department of Health has permitted 10 to 15 commercial brine disposal facilities to discharge under the Wildlife and Agricultural Use subcategory. Discharge limitations include pH between 6 and 9, a monthly average of 30 mg/l for total suspended solids, with a daily maximum of 45 mg/l, an oil and grease limit of 10 mg/l, a monthly average of 5,000 mg/l for total dissolved solids, with a daily maximum of 7,500 mg/l, and metal limits under the State water quality standards (Appendix A - CO). One brine treatment facility was visited during the field sampling portion of the Onshore Oil and Gas Study. This facility treated brines with chemical addition (borax, calcium hypochlorite, and potassium permanganate) and aeration. This facility did not discharge; rather, brines were placed in large evaporation ponds (EPA - CO, in press).

Alaska also has centralized brine treatment facilities. Produced waters from 14 platforms in Cook Inlet are sent to one of three treatment facilities. Treatment consists of heating to enhance oil/gas separation, solids settling, and surface skimming. The water is discharged off the coast (EPA - AL, 1985b).

Louisiana has approximately 33 commercial centralized facilities currently in operation. Some accept only brines, while others accept mud and brine. They must be permitted for operation by the State.

Treatment of reserve pit wastes can also be accomplished via mobile treatment units. Such units employ scaled-down equipment designed to perform the same treatment processes as those performed at centralized treatment facilities, except that the equipment is truck-mounted and is brought to the reserve pit onsite. Mobile treatment is discussed in greater detail in the section titled Onsite Treatment and Disposal.

Reconditioning/Recycling/Reuse

This section discusses the reconditioning and reuse of oil and gas drilling and production wastes. Not included here are the recycling and reuse of drilling fluids (i.e., drilling mud recirculation systems), since these are cited in the section on Closed Systems.

The reconditioning, recycling, or reuse of oil and gas wastes represents a positive environmental policy, when applicable. By means of chemical or physical treatment, a material that otherwise would have to be disposed of becomes a material with a beneficial use. In some cases, no adjustment of the waste material is needed to put it to an advantageous use. The recycling and reuse of these wastes not only can reduce the volume of generated wastes that requires disposal, but also can reduce the need for raw materials. This is especially important in geographical areas where onsite waste disposal is extremely difficult because of geological or other physical conditions, or not allowed because of regulation.

The State of Louisiana has regulations that specifically mention reusable oilfield waste. "Reusable material" is defined as a "material that would otherwise be classified as oilfield waste, but has been processed in part or in whole for reuse." Commercial facilities may produce reusable material as their treatment process or in conjunction with their treatment process. In either case, the facility must be permitted by the State. Onsite generation of reusable material requires approval from the State Office of Conservation. The reusable material must be tested and meet the following limitations:

Moisture content	<50 % by weight
pH	6.5 - 9.0
Conductivity	8 mmhos/cm
Sodium adsorption rate	12
Exchangeable sodium percentage	15%
Leachate test:	
Oil and grease	10.0 mg/l
Chlorides	500.0 mg/l
Leachate (EP Toxicity)	
Arsenic	0.5 mg/l
Barium	10.0 mg/l
Cadmium	0.1 mg/l
Chromium	0.5 mg/l
Lead	0.5 mg/l
Mercury	0.02 mg/l
Selenium	0.1 mg/l
Silver	0.5 mg/l
Zinc	5.0 mg/l

Louisiana has permitted reusable material that meets the above criteria to be used as landfill cover or various construction fill material (LA State Order 29-B).

A relatively new well-site treatment system offers beneficial material reuse. The technology mentioned earlier was proven on a French discovery well. This method is now being tested on several wells in the western United States (Neidhardt, 1985).

In Canada, a feasibility study was conducted on reusing produced water as the feedwater supply for steam generation for onsite oil recovery (Kus, 1984). Such steam-assisted methods operate with steam-to-oil ratios of 3 to 1 and generate 2 to 5 barrels of produced water per barrel of oil. To raise the large quantities of steam required for reservoir stimulation, once-through type steam generators are most commonly used. Preliminary investigations into the feasibility of using produced water as the only source of water proved to be uneconomical. As an alternative, a blend of produced water and municipal water was chosen (Kus, 1984).

EPA authorized a study on the feasibility of removing and recovering phenol and acetic acid from sodium chloride brine (EPA, 1973). A pilot plant was constructed to demonstrate the feasibility of using the method of fixed bed adsorption of activated carbon. Separate electrolytic test-cell evaluation of the purified brine showed it to be equivalent to pure brine. The carbon beds were regenerated with dilute sodium hydroxide. Desorbed phenol was recycled to a phenol manufacturer (EPA, 1973).

Incineration

This treatment method is applicable for organic and oil-laden wastes. These include oil-based muds, oil emulsions, and other muds and cuttings contaminated with oil, tank bottoms, and separator sludges. In theory, any drilling or production waste with a low enough water content can be economically combusted. The combustion residuals must also be disposed of. The practice of incinerating drilling and production wastes is not common. It is known to occur at a central treatment facility near Kenai, Alaska. This facility receives oil and water from the coastal rigs in Cook Inlet. All waste oil is collected in a storage tank where it is periodically removed and incinerated. The residuals are placed in a landfill on the facility property. Incineration is also known to be used on waste oil-laden cuttings and oil-based muds from offshore facilities in Louisiana. EPA will investigate further the extent of the use of incineration as a reliable waste treatment method.

Land Application

Landfarming

Landfarming, as defined by the Railroad Commission of Texas and used in this report, is "a waste management practice in which oil and gas wastes are mixed with or applied to the land surface in such a manner that the waste will not migrate off the landfarmed area." The ultimate goal of landfarming is to use dilution, chemical alteration, and biodegradation to decrease the level of pollutants and alter the waste so that the waste/soil mixture remains compatible with the intended or original land use (Freeman and Deuel, 1986).

Landfarming is generally viewed as a long-term, management-intensive process. Though widespread in Texas, Colorado, and Louisiana, and to a lesser degree in Mississippi and Alabama, it is not common in other States. Improperly managed landfarming sites have the potential for environmental damage. The State of Texas has identified improper landfarming and the resulting runoff to surface water as a critical environmental problem.

Landfarming can provide an efficient disposal method for various oil and gas wastes, including pit residue, sludges, muds, and liquids. Solid wastes can be distributed over the land surface and mixed with the soils by mechanical means. Liquids can be applied to the land surface by various types of irrigation, including sprinkler, flood, and ridge and furrow. Injection plowing and disking of irrigated land surfaces allow for subsurface application of wastes (Railroad Commission of Texas, 1985).

Certain criteria must be met, however, for successful landfarming. Chloride content of the wastes must be relatively low. For example, Texas allows non-permitted landfarming of wastes only if chloride content is less than or equal to 3,000 mg/l. Alabama requires a chloride content of less than 500 mg/l. Oklahoma permits spray-application of reserve pit fluids if chloride content is less than 1,000 mg/l.

Oily wastes and other organics is another concern. To alleviate this problem, some States allow only water-based drilling fluids to be landfarmed, and also limit oil and grease content of the wastes. Oklahoma requires less than or equal to 30 mg/l of oil and grease in wastes before allowing spray application. Disking, and the resulting soil aeration, also assists in the biodegradation of oil, grease, and other organics.

The presence of heavy metals (primarily barium, chromium, lead, and zinc, and, to a lesser extent, arsenic, cadmium, mercury, selenium, and silver) in drilling muds is also a concern (Kissock, 1986). The solution to this problem is to limit the landfarming of wastes with high metal content and to carefully maintain a soil pH range of 6.5 to 9.0, keeping the heavy metals insoluble and immobile.

In addition to these considerations, the site and design of the landfarming facility is a critical component in its success. Louisiana has developed location and facility design standards that address these concerns. These standards prohibit facilities in flood zones and wetlands, limit their proximity to existing buildings, require spill containment systems in loading and storage areas, and limit access to the sites (Field and Smith, 1986). Additional standards detail requirements of the treatment zone, including thickness, permeability, and relationship to the water table. This requires a detailed geological/geotechnical investigation of prospective landfarming sites.

Roadspraying

In addition to landfarming, there are other types of land applications for oil and gas wastes. In the past, pit and produced brines have been used for ice and dust control on roads in Michigan. This process, called roadspraying or roadspreading, is being discontinued by order of the State. Alaska is also reconsidering the use of brines for de-icing roads. Kansas still allows the spreading of brines on roads under construction, and in New York, road spreading for ice control is the predominant disposal method.

Subsurface Disposal

Subsurface disposal of oil or gas field waste is Federally regulated through the Underground Injection Control (UIC) Program, as detailed in Appendix A. States may be granted primacy over the UIC program as a result of EPA's evaluation and approval of State programs. Otherwise, EPA is the primary regulatory authority in matters of underground injection. However, States that do not have primacy may have regulations in addition to those imposed by the Federal UIC Program. Pennsylvania, for example, regulates underground disposal of oil and gas field wastes through the Clean Streams Law (Waite, et al., 1983).

One of the most common forms of liquid waste disposal used by the oil and gas industries is injection into non-producing formations (Waite, et al., 1983). Liquid waste is typically produced water (also known as brine) brought to the surface with the produced oil or gas. Historically, surface disposal of produced brine has been believed to cause severe environmental damage in States (EPA - OH, 1985a; EPA - IL, 1985a; EPA - NM, 1985b), which has led to the widespread use of subsurface injection methods.

Brine is injected to non-producing formations (or "safe horizons") by two methods. The method often preferred by State regulatory agencies is the use of disposal wells specifically drilled, cased, and completed to accommodate brine. Figure I-8 displays a typical saltwater disposal well pumping into a zone located far below the freshwater table (Elmer E. Templeton and Associates, 1980). New wells may be constructed for this purpose, or old wells may be retrofitted to meet construction requirements. The second method is injection into the uncased annular space of a producing well, or in the space within the production casing. Figures I-9 and I-10 illustrate these techniques (Templeton, 1980). Annular disposal of brine to non-producing zones has been or is being phased out of many States (Elmer E. Templeton and Associates, 1980). Louisiana allows annular injection of reserve pit fluids whenever the surface casing is deep enough to protect underground sources of drinking water (Appendix A - LA).

Wells used for brine disposal must be carefully constructed in order to protect freshwater aquifers. When old wells are retrofitted for brine disposal, ground-water contamination may occur as a result of casing failure. Consideration must also be given to abandoned wells in the vicinity of a proposed disposal well site. Figure I-11 illustrates the potential for freshwater contamination created by abandoned wells (Illinois EPA, 1978).

In addition to construction requirements, injection pressure must be determined such that it successfully disposes of waste fluids without

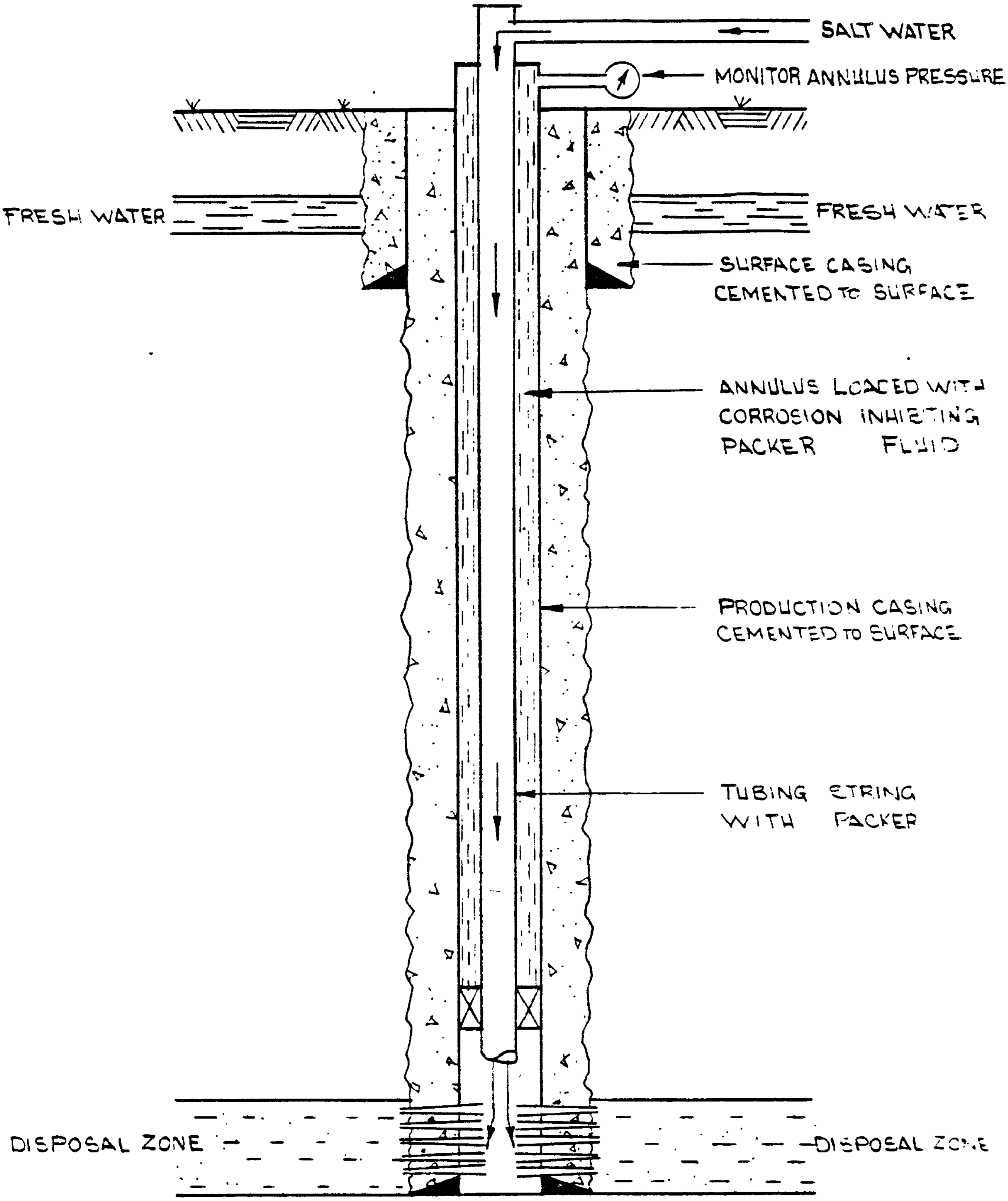

Figure I-8. Brine (saltwater) disposal well design.

Source: Templeton, Elmer E., and Associates, Environmentally Acceptable Disposal of Salt Brines Produced with Oil and Gas, January, 1980.

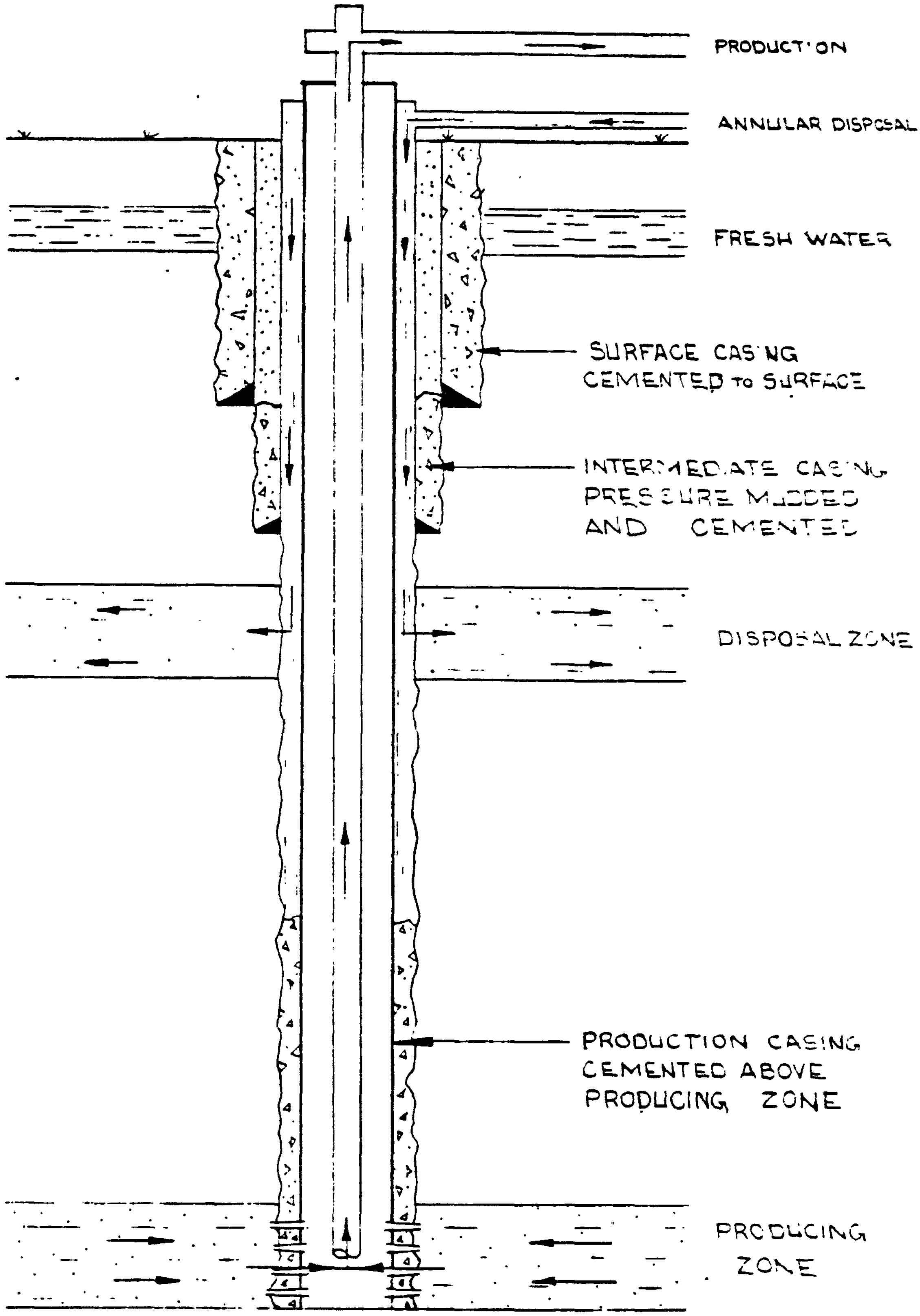

Figure I-9. Annular disposal outside production casing.

Source: Templeton, Elmer E., and Associates, Environmentally Acceptable Disposal of Salt Brines Produced with Oil and Gas, January, 1980.

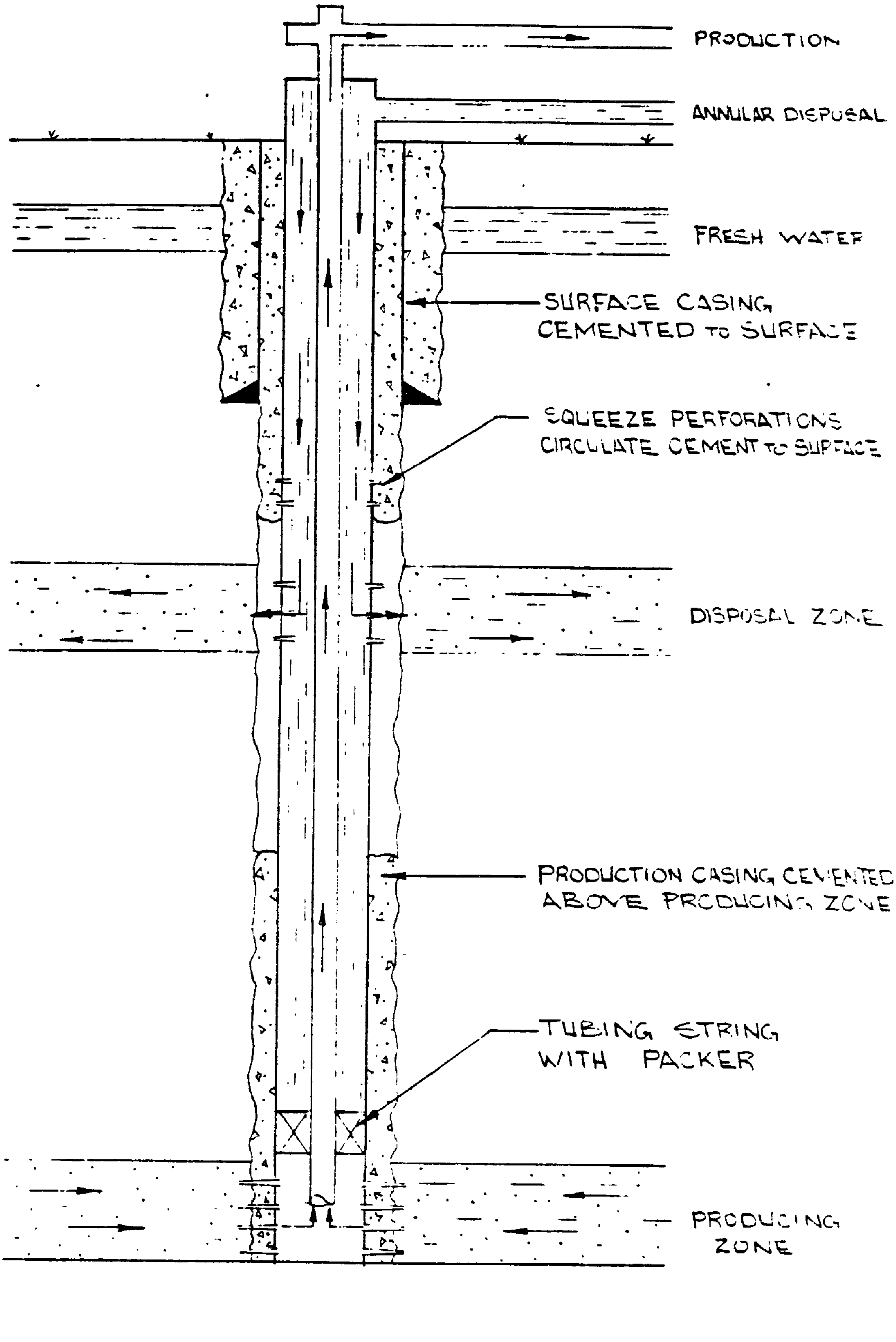

Figure I-10. Annular disposal within production casing.

Source: Templeton, Elmer E., and Associates, Environmentally Acceptable Disposal of Salt Brines Produced with Oil and Gas, January, 1980.

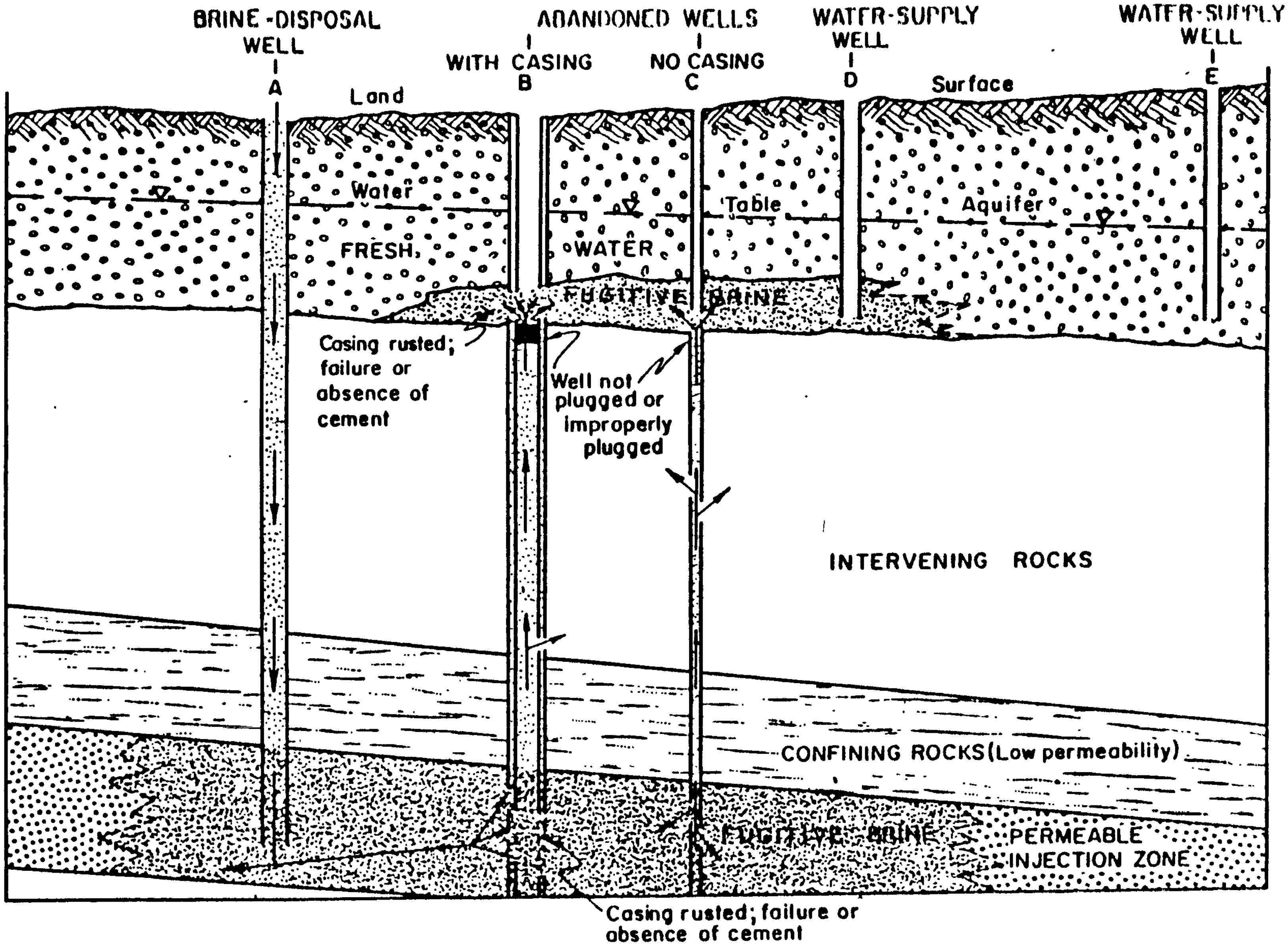

Figure I-11. Pollution of a fresh water aquifer through abandoned wells.

Source: Illinois EPA, Illinois Oil Field Brine Disposal Assessment: Staff Report, November 1978.

propagating fractures (Waite et al., 1983). Estimated maximum and average injection pressures must be included in applications for UIC permits (40 CFR 146.22).

Pretreatment of wastes prior to injection is used in locations of low permeability in order to extend the life of disposal wells. In Pennsylvania, pretreatment methods that have been used include settling, filtration, and flocculation. These treatment steps are enhanced by the addition of corrosion inhibitors, bactericides, and other additives used to adjust pH or prevent undesired precipitation in the disposal reservoir (Waite et al., 1983).

Another subsurface brine disposal alternative is injection of brine into producing zones for the purpose of enhancing oil or gas production. This secondary form of recovery is referred to as "water flooding," and may utilize surface water in addition to produced water. This is a widely accepted method of reusing produced water.

Drilling fluids and reserve pit wastes also can be disposed of by a one-time annular injection, depending on the geological formations. This type of subsurface disposal is preferred by some States because it eliminates surface disposal problems. Oklahoma, for example, allows this type of disposal, provided the well to be used has surface casing at least 200 feet below the depth of the base of the treatable water (McCaskill, 1985). Oklahoma sets no limit on the quantity of waste to be disposed of in this manner, because this is a one-time act of disposal, unlike continuous disposal of produced brine. Examples of other States that allow the annular injection of drilling fluid are Mississippi (EPA - MS, 1985a) and Alaska (EPA - AK, in press).

The intention of subsurface disposal of any waste is to avoid treatment or hauling costs that would otherwise be required. Therefore, a well and associated formation must be permeable enough to accept all the waste generated onsite, or another disposal alternative must be employed. In many areas, the alternatives are either costly or not allowed by State regulations (Ohio EPA, 1983).

Ocean Discharge

The U.S. Environmental Protection Agency has established guidelines for "Issuance of National Pollution Discharge Elimination System (NPDES) permits for the discharge of pollutants from a point source into the territorial seas, the contiguous zone, and the oceans" (40 CFR 125, Subpart M), as required by Section 403 of the Federal Clean Water Act. The guidelines are designed to "Prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal" (Federal Register, October 3, 1980).

In general, ocean discharge of wastes from onshore and coastal oil and gas field operations is regulated on a case-by-case basis. States that have NPDES programs oversee the permitting of any discharges or dumping along the coast or in marine waters. States that do not have NPDES programs, such as Louisiana and Texas, establish guidelines in coordination with Regional EPA offices.

An example of State-established effluent limitations is California's "Water Quality Control Plan for Ocean Waters of California," also called "The Ocean Plan." The Ocean Plan defines Water Quality Objectives, based on bacteriological, physical, chemical, biological, and radioactive characteristics, such that ocean disposal will not violate the objectives. The Ocean Plan next defines General Requirements for Management of Wastes and Effluent Quality Requirements.

The General Requirements specify constituents that must not be present in waste discharges, such as floatable particulates, settleable material that may be harmful to aquatic life, and materials that result in discoloration of the ocean surface. Another General Requirement states that waste discharges must be sufficiently diluted so as to minimize concentrations of substances not previously removed by treatment. Finally, the General Requirements call for a "detailed assessment of the oceanographic characteristics and current patterns" in order to determine a discharge location that will protect shellfish harvesting areas, areas of special biological significance, and the overall marine environment.

Effluent Quality Requirements are specified in Tables A and B of Chapter IV of the Plan. Table A, presented here as Table I-12, applies only to discharges not covered by Sections 301, 302, 304, or 306 of the Federal Clean Water Act. Table B, presented here as Table I-13, applies to all discharges within the jurisdiction of the Plan.

In California, wells located in the Santa Maria Basin were granted a suspension to the onshore oil and gas effluent limitations guidelines requiring "zero discharge" of any wastewater pollutants (Federal Register, July 21, 1982). Exception was made for this area because of the geologic and hydrogeologic problems associated with reinjection of produced water, the normal disposal method.

Other companies, located outside the Santa Maria Basin and interested in obtaining permits that would allow ocean discharge, have investigated possible methods by which produced water can be disposed of.

TABLE I-12

CALIFORNIA OCEAN PLAN: MAJOR WASTEWATER CONSTITUENTS AND PROPERTIES

	Unit of measurement	Limiting Concentrations Monthly (30 day Average)	Weekly (7 day Average)	Maximum at any time
Grease and Oil	mg/l	25	40	75
Suspended Solids		see below+		
Settleable Solids	mg/l	1.0	1.5	3.0
Turbidity	JTU	75	100	225
pH	units	within limits of 6.0 to 9.0 at all times		
Toxicity Concentration	tu	1.5	2.0	2.5

+Suspended Solids: Dischargers shall, as a 30-day average, remove 75% of suspended solids from the influent stream before discharging wastewaters to the ocean*, except that the effluent limitation to be met shall not be lower than 60 mg/l. Regional Boards may, with the concurrence of the State Board and the Environmental Protection Agency, adjust the lower effluent concentration limit (the 60 mg/l above) to suit the environmental and effluent characteristics of the discharge. As a further consideration in making such adjustment, Regional Boards should evaluate effects on existing and potential water* reclamation projects.

If the lower effluent concentration limit is adjusted by the Regional Board, the discharger shall remove 75% of suspended solids from the influent stream at any time the influent concentration exceeds four times such adjusted effluent limit.

Source: Water Quality Control Plan for Ocean Waters of California, November 17, 1983.

TABLE I-13

CALIFORNIA OCEAN PLAN: TOXIC MATERIALS LIMITATIONS

		Limiting Concentrations		
	Unit of Measurement	6-Month Median	Daily Maximum	Instantaneous Maximum
Arsenic	ug/l	8	32	80
Cadmium	ug/l	3	12	30
Chromium (Cr+6)	ug/l	2	8	20
Copper	ug/l	5	20	50
Lead	ug/l	8	32	80
Mercury	ug/l	0.14	0.56	1.4
Nickel	ug/l	20	80	200
Silver	ug/l	0.45	1.8	4.5
Zinc	ug/l	20	80	200
Cyanide	ug/l	5	20	50
Total Chlorine Residual (continuous sources)	ug/l	2	11	124
Ammonia (expressed as nitrogen)	ug/l	600	2,400	6,000
Toxicity Concentration	tu	0.05	-	-
Phenolic Compounds (non-chlorinated)	ug/l	30	120	300
Chlorinated Phenolics	ug/l	1	4	10
Aldrin and Dieldrin	ug/l	0.002	0.004	0.006
Chlordane and Related Compounds	ug/l	0.003	0.006	0.009
DDT and Derivatives	ug/l	0.001	0.002	0.003
Endrin	ug/l	0.002	0.004	0.006
HCH	ug/l	0.004	0.008	0.012
PCB's	ug/l	0.003	0.006	0.009
Toxaphene	ug/l	0.007	0.014	0.021
Radioactivity	Not to exceed limits specified in Section 30269 of the California Administrative Code.			

Source: Water Quality Control Plan for Ocean Waters of California, November 17, 1983.

One particular study investigated several methods including ocean discharge via pipeline, river discharge, percolation/evaporation pond disposal, effluent irrigation disposal, and other alternative methods (CH_2M Hill, 1983). The proposed ocean discharge alternative is presented in two parts: a treatment system and outfall design, and pipeline route considerations. The treatment system includes three process steps:

- Induced gas flotation for oil and suspended solids removal;
- Filtration for final oil removal and effluent polishing; and
- A minimum dilution of 100:1 to be achieved by the ocean outfall.

Design criteria for two alternative pipeline routes are based on pipeline orientation, pumping requirements, and piping requirements. Both the treatment system and the pipeline routes are designed to meet the anticipated ocean discharge effluent limitations defined by the California Ocean Plan (CH_2M Hill, 1983).

Alaska permits ocean discharge of oil and gas drilling waste according to applicable Federal NPDES requirements. The permitting authority is U.S. EPA Region X. Alaska does not have its own NPDES program. Statutory bases on which permits are written in this State are derived from the Federal Clean Water Act, Sections 301(b), 304, 308, 401, 402, and 403, and include technology-based effluent limitations, ocean discharge criteria, and State of Alaska standards and limitations (U.S. EPA Region X, 1985). Specific permit requirements allow discharge of "generic [drilling] muds and authorized additives," listed in Table I-14. Under this provision, drill cuttings that meet specified content requirements may be discharged "without special permission" (U.S. EPA Region X, 1985).

TABLE I-14

U.S. EPA REGION X: AUTHORIZED DRILLING MUD TYPES

Components	Maximum Allowable Concentration (lb/bbl)
1. Seawater/Freshwater/Potassium/Polymer Mud	
KCl	50
Starch	12
Cellulose Polymer	5
Xanthan Gum Polymer	2
Drilled Solids	100
Caustic	3
Barite	450
Seawater or Freshwater	As needed
2. Seawater/Lignosulfonate Mud	
Attapulgite or Bentonite	50
Lignosulfonate, Chrome or Ferrochrome	15
Lignite, Untreated or Chrome-treated	10
Caustic	5
Barite	450
Drilled Solids	100
Soda Ash/Sodium Bicarbonate	2
Cellulose Polymer	5
Seawater	As needed
3. Lime Mud	
Lime	20
Bentonite	50
Lignosulfonate, Chrome or Ferrochrome	15
Lignite, Untreated or Chrome-treated	10
Caustic	5
Barite	180
Drilled Solids	100
Soda Ash/Sodium Bicarbonate	2
Seawater or Freshwater	As needed
4. Nondispersed Mud	
Bentonite	15
Acrylic Polymer	2
Barite	180
Drilled Solids	70
Seawater or Freshwater	As needed

Components	Maximum Allowable Concentration (lb/bbl)
5. Spud Mud	
Lime	1
Attapulgite or Bentonite	50
Caustic	2
Barite	50
Soda Ash/Sodium Bicarbonate	2
Seawater	As needed
6. Seawater/Freshwater Gel Mud	
Lime	2
Attapulgite or Bentonite	50
Caustic	3
Barite	50
Drilled Solids	100
Soda Ash/Sodium Bicarbonate	2
Cellulose Polymer	2
Seawater or Freshwater	As needed
7. Lightly Treated Lignosulfonate Freshwater/Seawater Mud	
Lime	2
Bentonite	50
Lignosulfonate, Chrome or Ferrochrome	6
Lignite, Untreated or Chrome-treated	4
Caustic	3
Barite	180
Drilled Solids	100
Soda Ash/Sodium Bicarbonate	2
Cellulose Polymer	2
Seawater & Freshwater in 1:1 ratio	As needed
8. Lignosulfonate Freshwater Mud	
Lime	2
Bentonite	50
Lignosulfonate, Chrome or Ferrochrome	15
Lignite, Untreated or Chrome-treated	10
Caustic	5
Barite	450
Drilled Solids	100
Soda Ash/Sodium Bicarbonate	2
Cellulose Polymer	2
Freshwater	As needed

Source: NPDES Permit No. AK-004497-1 (draft), 1985.

In general, ocean discharge of oil and gas field wastes is viewed by concerned State agencies as an acceptable discharge alternative, provided that effluent limitations are observed by the industry (EPA - CA, 1985).

CONSTRUCTION AND MONITORING REQUIREMENTS

Introduction

There is wide variation among governmental entities regarding construction and monitoring requirements associated with pits, sumps, or impoundments used to contain wastes generated from drilling and production operations. This section of the report discusses design and construction features, and provide examples of impoundments and centralized/offsite pits as prescribed for Federal lands and by States.

The terms "sump," "impoundment," "pond," and "lagoon" often are used synonymously to describe a pit (EPA, 1983). The pit consists of an excavation of predetermined size and shape, and may be lined or unlined depending upon the intended purpose.

In the 1983 EPA Surface Impoundment Assessment National Report, the following statistics were determined from a sample population of oil and gas sites:

- Thirty-one percent (64,951) of all sites (176,242) were oil and gas sites. (Pits associated with drilling activities were excluded.)
- Thirty-seven percent of all impoundments were associated with the oil and gas category.

- Through the randomization of site selection, only 13 percent of the located oil and gas sites and 5 percent of the oil and gas impoundments were assessed.

- Disposal is the primary purpose of 67 percent of the oil and gas impoundments, with 29 percent being used for storage (i.e., emergency pits), and 4 percent being used for treatment prior to discharge (usually oil skimming).

- Only 20 percent of the oil and gas impoundments were lined. For this report, however, the definition of a liner did not consider mixing bentonite with native soil or compacted soils as liners.

In the exploration and development phases, reserve pits are used to store drilling fluids, cuttings, and associated wastes produced by drilling. At the drill site, there may be one reserve pit to handle all drilling wastes or several individual pits to serve different purposes, such as containing fresh "make-up" water, holding circulating mud prior to disposal in the reserve pit, holding well treatment fluids (fracture fluids), acting as an emergency pit, and acting as a test pit. These pits generally are constructed for temporary use and are backfilled at the end of drilling operations.

During the production phase, pits are utilized for several different purposes. A pit is constructed to hold produced waters. This pit is designed for the long-term storage and evaporation of fluids associated with the production of oil and gas. At wells that are reinjecting fluids, long-term storage pits are constructed to act as settling/holding ponds for the injection fluid.

In general, pit construction practices are left to the discretion of the company and subsequently pit designs vary widely throughout the oil and gas industry. Many parameters must be taken into consideration in the proper design and construction of a pit, including facility layout, function, location of drilling rig, location of adjacent water bodies, geology, climatology, topography, volume of waste, ground-water hydraulic gradient, characteristics of waste, and soil characteristics.

The following is a brief synopsis of specific pit design and construction criteria for the containment of wastes associated with exploration, development, and production of oil and gas.

Pit Design and Construction Features

Pit Types

Reserve pits. Proper location and construction of pits facilitate the reclamation process and help prevent problems such as leakage and pit wall failure. Ideally, a pit should be excavated from undisturbed, stable subsoil to prevent pit wall failure. For areas where excavating below ground level cannot be done, the pit berm is usually constructed as an earthen dam. Sidewalls should be constructed with a slope of less than 3:1 to give support and minimize seepage. Whenever possible, a reserve pit should not be constructed on sloping ground or near the edge of a hill top. This is often impossible to avoid, which means that the hillside must be contoured in such a way that the runoff water is diverted around the drilling location and reserve pit. Pits should be located a minimum of 300 feet laterally from the high water mark of the nearest water body and/or intermittent water courses, according to one source (MoeCo, 1984). The site chosen should be high enough to escape flooding in heavy rains. A reserve pit is typically excavated directly adjacent to where the rig and associated mud equipment will be sited; however, in recent years, a growing practice for disposal of drilling fluids has involved the use of centralized pits.

Centralized pits are larger than onsite pits, and they may serve the disposal needs for drilling or production wastes from multiple wells over large geographical areas. Centralized pits should be close to drilling and production sites to be cost-effective, yet they should be located in environmentally safe areas. A site removed from well-defined drainage basins will minimize the potential for surface water pollution from heavy runoff (Univ. of Oklahoma, 1984).

The reserve pit should be of adequate size to properly contain the drilling fluid. The reserve pit volume should allow for ample freeboard when the pit is full. The purpose of freeboard is to create a margin of safety to protect against unexpected drilling conditions and unpredictable elements in planning the mud program. Increasing drilling depth increases the drilling fluid volume and therefore more reserve pit capacity may be required. Overfilling the pit has presented significant problems in the past. In the case of an offsite pit, the design volume is generally a function of land availability and topography, along with business-related estimates of drilling fluid volumes likely to be generated within the potential geographical service area (Univ. of Oklahoma, 1984).

Percolation pits. There is a certain controversy over whether percolation or seepage is an allowable alternative to evaporation in areas with humid climates (Illinois EPA, 1978). Regulations concerning the matter vary from State to State. Many State regulations prohibit the use of percolation pits; some States require a ground-water discharge permit for their use. A percolation pit is an unlined pit in which substantial waste volume percolates to the ground, with some loss through evaporation. The percolation pit is designed and located to maximize the infiltration of waste through the soil profile. The critical limitations for any specific site would be the depth to ground water, ground-water quality, actual or potential use of ground water, and the existence of any impermeable layers within the soil profile. Percolation pits must be sited in areas where the distance to ground water is great and where there are no restrictions to infiltration. In addition, the location of the percolation pit could depend on the location and quality of the underlying ground-water aquifer. Percolation can adversely affect the ground-water quality. Percolation pits often are designed with several cells, so that one cell can be cleaned or raked if necessary to improve filtration while others are in use (CH_2M Hill, 1983). Percolation pits are not always suitable for all waste materials, and seepage can result in the formation of pockets of salt in the underlying soil. These salts can slowly migrate to ground water via leaching (Univ. of Oklahoma, 1984).

Evaporation pits. When properly designed, constructed, and operated, evaporation pits rely on the atmosphere to concentrate brines or drilling fluids by removal of water as vapor. The relationship between the local precipitation and evaporation rates should therefore be considered. The successful operation of such a pit depends on the annual net evaporation rate of the brine or drilling fluid. The presence of dissolved solids and oil films lowers the evaporation rate. Other variables influencing the rate include the air and brine temperature, relative humidity, and wind speed (Reid, et al., 1974). If the space at the drilling location is adequate, it is preferable to have a larger, more shallow evaporation pit, because the increased surface-area-to-volume ratio enhances the evaporation rate and final disposal can be achieved more quickly and efficiently. When suitable foundation soils are not available, alternatives must be sought such as lining with clay, concrete, or asphalt or employing a synthetic material to line the pit (MoeCo, 1984).

Pit Liners

Natural pit sealing has been found to occur when the settled solids form a bottom layer that physically clogs the soil pores (Univ. of Oklahoma, 1984). This can occur most effectively with certain types of drilling fluids, and many drill operators count on this phenomenon to seal mud pits (Freeman and Deuel, 1986). In permeable soils, however, natural sealing may not afford enough protection and earthen pits should be lined with an impermeable material. Many types of man-made pit liners exist, and they can be classified into two major categories: (1) synthetic and rubber liners and (2) earthen and cement liners. Also, there is a wide variety of application characteristics within each of these categories. Choosing the appropriate lining for a specific site is a critical issue in the design for seepage control. The criteria for lining a pit are highly dependent on the specific geographical location, climate, local hydrogeology, and the characteristics of the waste material.

Synthetic and rubber liners. Synthetic and rubber liners include PVC, butyl rubber, neoprene, and hypalon. Synthetic liners are popular in applications requiring essentially zero permeability. These materials are economical and resistant to most chemicals when selected and installed properly. However, many are susceptible to degradation by ultraviolet rays and, therefore, should not be used in long-term impoundments. Further, there is disagreement regarding the level of tensile strength and puncture resistance needed (Western Workshop, EPA, 1985). Standard procedures for installing and maintaining synthetic membrane liners suggest that side slopes should not exceed a ratio of 3:1 and subgrade surface should be dragged for sharp rocks and rolled smooth. A layer of clay is applied as a base for the membrane liner. Generally, membrane liners are made from sheets of 0.008 inch or thinner and must be protected from mechanical damage. As a protective measure, the liners are often buried (Univ. of Oklahoma, 1984). The effectiveness of the membrane liner depends on not being punctured or torn during installation or use. It is, therefore, imperative that liners meet proper strength and durability specifications and are employed properly.

Earthen and cement liners. Bentonite, asphalt, and soil cement have been used as linings for pits and reservoirs for several decades. Bentonite is a sodium-type montmorillonite clay and exhibits a high degree of swelling, imperviousness, and low stability in the presence of water. Seepage losses for bentonite-lined pits represent about a 60 percent improvement over unlined pits (Univ. of Oklahoma, 1984). The construction approach for using bentonite to line pits involves overexcavating the area to allow for the added layer of clay. Side slopes should not exceed 2:1. The subgrade is smoothed and dusted and the bentonite layer applied over the top. Permeability of bentonite linings is greatly affected by the quality of the bentonite. If the bentonite is finer than a No. 30 sieve, it should be used without specifying size gradation, but if the material is coarser than the No. 30 sieve, it should be well-graded. Bentonite tends to crack and deteriorate if allowed to dry; therefore, a protective blanket of soil is usually placed over the bentonite layer.

Asphalt linings composed of prefabricated buried materials can be used for both onsite and offsite disposal pits, since the amount of special equipment and labor connected with installation is minimal. Asphalt membrane linings can be constructed at any time of year. Its convenient usage in canals and ponds may dictate that buried asphalt membrane lining is the appropriate one to use in many cases. Asphalt has been used extensively as a lining material for brine storage basins (Ostroff, 1965).

Examples of Drilling Pit/Impoundment Permit Requirements

Drilling Reserve Pits

Often States do not issue permits relating to drill pits or reserve pits. Monitoring generally is not required; construction requirements vary. Some States have construction guidelines covering above or below ground construction, required freeboard, and compaction. Pits typically are unlined. Such pits contain drilling cuttings, contaminated fresh and salt water produced during construction and well stimulation, and various additives used during drilling and well stimulation. Often pits are not reclaimed, nor is there a permit required for a drill pit, nor a contingency fund required for management of abandoned pits (Appendix A - PA).

General language is used in other State regulations to require that mud pits, sumps, reserve pits, or tanks be of sufficient size and managed to prevent contamination of ground water and damage to the surface environment. After a well is completed or abandoned, the fluids are to be removed and disposed of properly, and all mud pits, sumps, reserve pits, and dikes usually must be backfilled with earth or graded and compacted in such a manner as to be returned to a nearly natural state.

There may or may not be a requirement for lining with plastic or an impervious material and, generally, such pits must be closed within 12 to 18 months. Often, the pits are placed in wetlands (Summary of State Regulations - Alaska, California, Ohio, Oregon, North Dakota, South Dakota; Alabama Oil and Gas Administrative Code 400-1-5-.03; Alaska Oil and Gas Commission 20 AAC 25.047; Georgia Department of Natural Resources 391-3-13(11); Oklahoma Oil and Gas Conservation Division Rule 3-110.1; and Tennessee State Oil and Gas Board 1040-3-3-.02). Generally, State agencies do not prescribe drilling pit construction conditions.

More specific instructions are supplied to a driller by the Arkansas Department of Pollution Control and Ecology through a Letter of Authorization. Reserve pits must be constructed with either a synthetic liner of at least 20 mils thickness or an 18- to 24-inch compacted clay liner. Such reserve pits must maintain at least a 2-foot freeboard. Pits must be closed within 60 days after the drilling rig is removed from the site. In Utah, saltwater and oil field wastes associated with the drilling process may be disposed of by evaporation if impounded in excavated earthen reserve pits underlain by tight soil or lined (Rule 309 - Utah Oil and Gas Commission).

A Letter of Instruction was issued by the Michigan Supervisor of Wells on April 6, 1981, which provided for a two-pit drilling mud system--one for freshwater muds and one for saltwater muds--and required that all reserve pits receiving other than freshwater fluids be lined with 20 ml PVC or an equivalent liner as approved. Instructions in 1985 require that all mud pits be lined with an impervious material that will meet or exceed specifications for 20 mil virgin PVC. Liners shall be one piece, or with factory-installed seams, and shall be installed in a manner sufficient to prevent both vertical and lateral leakage. A revised Supervisor Instruction, effective February 1, 1985, requires that cellars shall be sealed, and rat holes and mouse holes shall be equipped with a closed-end steel liner or otherwise sealed or cased in such a manner that all fluids entering the cellar, rat hole, and/or mouse hole shall not be released to the ground but shall be discharged to steel tanks, the lined reserve pit, or the mud circulation system. Aprons of 20 mil virgin PVC or other equivalent material shall be installed under steel mud tanks and overlapping the mud pit apron, and in ditches or under pipes used for brine conveyance from cellars to pits or to steel mud tanks (Appendix A - MI).

Production Impoundments

Montana allows evaporation of production salt water when impounded in excavated earthen pits underlain by tight soil such as heavy clay (Oil and Gas Conservation Division 36.22.1227). California uses lined sumps for evaporation of produced fluids (Appendix A - CA). The Colorado Oil and Gas Conservation Commission in 1984, Rule 325, specifies that if domestic water supplies are found to immediately underlie significant geographical areas and are not separated from the surface by a confining layer, it is to be proposed to the Commission that a rule be adopted to require all produced fluid retaining pits in the area to be lined and properly constructed so as to prevent pollution.

Wyoming exercises its regulatory authority over the construction location, operation, and reclamation of produced water pits that are used for the storage, treatment, and disposal of production and treated unit wastes. After June 1, 1984, no earthen retaining pit can be constructed without a permit. Produced water pits that receive less than 5 barrels of water per day on a monthly basis may be exempt from the formal permit. Owners of produced water retaining pits in operation prior to June 1, 1984, may continue with such operation as long as it causes no endangerment to the State's waters and as long as the operation conforms to the requirements of new pits. When any retaining pit is sited in an area where the potential for communication between the pit contents and surface water or shallow ground water is high, the Commission may require lining or waterproofing of any retaining pit, installation of monitoring systems and provisions for reporting, and any other reasonable requirement that will assure the protection of fresh water. Unlined pits must not be constructed on fills. Pits must not be constructed in a drainage, or in the flood plain of a flowing or intermittent stream, or in an area where there is standing water during any portion of the year (Wyoming Oil and Gas Commission Rule 326).

Rule 632-10-192 of the Oregon Department of Geology and Mineral Industries provides for saltwater disposal in excavated earthen evaporation pits that are lined with impervious material. All pits must have a continuous embankment surrounding them sufficiently above the level of the surface to prevent surface water from running into the pit. Illinois also provides for saltwater evaporation in lined pits (Illinois Division of Oil and Gas Rule 1X(2)(a)). Mississippi requires temporary saltwater storage pits to be lined with an impervious material. Salt water must never rise to within 1 foot of the top of the pit walls or dikes (Rule 63.III.E.3).

In proposed Rule 83-3-600, the State Corporation Commission of the State of Kansas would require all surface permitted ponds to have 30 inches of freeboard; observation trenches, holes, or wells, if required; and be sealed with artificial materials if it is determined that an unsealed condition will present a pollution threat to soil or water resources.

The Utah Water Pollution Control Committee, in Part VI, 6.4 of wastewater disposal regulations, requires surface disposal ponds to be fenced and properly netted to prevent access by waterfowl, to have a minimum 2 feet of freeboard, and to be lined. Each pond used for disposal of more than 100 barrels per day of produced water is required to have monitoring wells and leak detection technology in both vertical and horizontal directions. Detailed instructions are provided for onsite containment soil and for liners.

The Railroad Commission of Texas has issued a Water Protection Manual, published by the Texas Oil and Gas Division, which provides design and construction techniques for pits proposed for long-term, continuous use that must be authorized by permit. All earthen dikes surrounding pits should be constructed of soil material that is capable of achieving a permeability of 1 x 10^{-7} cm/sec or less when compacted. During construction, successive lifts should not exceed 9 inches in thickness, and the surface between lifts should be scarified to achieve a good seal. The dike height and width should be consistent with the volume of wastewater to be retained. When wastewater is retained in aboveground pits, it is recommended that the top width of the dike be at least 4 feet and the side slopes not be steeper than 3 to 1 (3 feet horizontal to 1 foot vertical). Dikes for all pits are "keyed" into the underlying soil to achieve a good seal between the ground and the bottom of the dike to prevent lateral seepage of wastewater through the base of the dike. Two of the most common construction methods for pits are "above ground" and "below ground." The aboveground pit should be used in areas where the water table is high. The aboveground method consists of constructing dikes around the area without excavating below the surface. The below-ground method of constructing a pit consists of excavating an area and building dikes around the excavation. The below-ground pit should be used in areas where the water table is well below the surface.

A proposed rule of the Alaska Oil and Gas Commission would require monitoring of surface ponds to include at least three ground-water monitoring wells and may include a leachate collecting and sampling system designed to collect any waste or leachate escaping as a result of the failure of the primary liner. Finally, the Letter of Authorization from the Arkansas Department of Pollution Control and Ecology requires produced salt water to be stored in a plastic or fiberglass tank above ground and resting on a concrete pad.

Centralized/Offsite Pits

On the western side of the San Joaquin Valley, California, there is a wastewater disposal facility permitted on Federal land where the oil industry has cooperated with a private consultant and formed a series of sumps that cover approximately 20 to 40 acres. These sumps are used for percolation and evaporation (Summary of State Regulations - California).

Rule 325 of the 1984 Rules of the Colorado Oil and Gas Commission requires an impervious, weather-resistant lining, a leak detection system, monitoring wells, and an opportunity for State inspection of the leak detection system, the liner, and cover material for the liner.

Rule 3-110.2 of the Oklahoma Corporation Commission permits the use of centralized earthen pits provided they are sealed with an impervious material, do not receive outside runoff water, and are filled and leveled within 1 year after abandonment. The chloride content of the contained fluids must not exceed 3,500 mg/l. Centralized pits are created by excavating, damming gullies, and using abandoned strip pits. Every centralized earthen pit must be completely enclosed by a permanent woven wire fence of at least 4 feet in height. No centralized earthen pit is allowed to contain a soil seal less than 12 inches thick with the coefficient of permeability no greater than 10^{-7} cm/sec. New pits are required to have monitoring wells, which are sampled principally for chlorides and pH. There is currently a proposal to make such requirement applicable to existing centralized pits. Three wells would be required--one upgradient and two downgradient. Any indicated change over background in the constituent levels tested would indicate potential pollution.

Federal Lands

The Bureau of Land Management (BLM) approves the use, on Federal lands, of unlined surface pits as a temporary means of storage of fluids associated with drilling, redrilling, reworking, deepening, or plugging of a well. Such pits must be promptly and properly emptied and restored upon completion of the operations; they may be used for well evaluation purposes for 30 days (see Appendix A. Summary of Federal Regulations - Bureau of Land Management).

Generally, BLM authorizes unlined pits when: (1) input fluid volume averages 5 barrels or less per day, (2) the total dissolved solids is less than 5,000 mg/l, (3) water will be used for livestock or wildlife watering or irrigation, (4) well fluids are of better quality than area's surface or subsurface waters, and (5) a discharge is allowed by an NPDES permit.

The Bureau of Land Management permits disposal of produced water into lined and unlined pits, but all such pits must: (1) have adequate storage, (2) be maintained to prevent surface discharge, (3) be fenced to preclude large animal entrance, (4) be maintained free from floating oils, and (5) be constructed away from established drainage areas and to prevent surface water entrance.

For longer-term, lined, produced water disposal pits, leak detection underlying a gravel-filled sump and lateral system is required. Monitoring is limited to total dissolved solids, pH, chlorides, and sulfates.

EVALUATION OF WASTE MANAGEMENT METHODS

An evaluation of disposal methods will be conducted for waste disposal techniques. Disposal methods will be examined to determine their effectiveness in removing (or mitigating the environmental effects of) the pollutants identified during the screening sampling program conducted June - September 1986 on wastes from onshore oil and gas sources. Analytical results from the screening sampling program will be presented in the EPA Technical Report due January 31, 1987.

Identification of waste management practices has been accomplished through research into published and unpublished literature, through extensive contact with State regulatory agencies, through observation during the screening sampling program, and through interviews. The control/disposal practices identified through this research were presented earlier in this chapter.

Waste management practices other than those identified in this report may be appropriate for particular pollutants, groups of similar pollutants, or estimated pollutant loadings. Identification of alternative waste management practices would be questionable, however, if it was based only on the limited data available from the literature. The literature contains little data regarding the full range of constituents in oil and gas wastes (see Literature Review under Waste Generation). Thus, identification of alternative treatment and disposal technologies will be directed by the analytical results from the screening sampling program previously mentioned. Detailed sample site documentation, in addition to the analytical results, will be part of the January 1987 technical report.

Alternative technologies will be identified based on historical evaluations of their effectiveness for handling particular pollutants, groups of similar pollutants, or pollutant loadings as targeted by analytical data from the screening sampling program. Technology transfer and data for new treatment methods under development will also be considered.

When the data are available, the effectiveness of waste management practices will be evaluated based on:

- Fundamental chemical and/or engineering concepts;
- Treatability or other related information from the literature;

- Best estimates based on professional engineering judgments; and
- Environmental conditions.

It is anticipated that the evaluation of control/disposal techniques will be presented in detail in the final technical report. For ease of understanding, however, the effectiveness of the technology may be ranked in ranges appropriate to distinguish between levels of performance. Mitigating circumstances affecting the performance of a particular technology (e.g., the use of evaporation pits in areas of net precipitation) will also be presented.

If the analytical data present a relatively limited list of pollutants of concern, a matrix will be constructed identifying the major pollutant loadings in each waste stream, current waste management practices, and alternative control/disposal techniques, as illustrated by the example in Figure I-12. (If the pollutant list is extensive, an effort will be made to construct the matrix presenting only the most hazardous, difficult to treat, or highly concentrated pollutants.) Entries in the matrix will be codified to indicate the estimated effectiveness of waste management practices for each pollutant found in concentrations of concern. The matrix will serve as a summary of a detailed discussion of the evaluation for each waste management practice.

Some alternative waste management practices will be identified for control or treatment of particular pollutants. It is expected that literature regarding treatability or other aspects of the technique(s) which mitigate environmental effects will provide a basis for the evaluation.

Major pollutants	CURRENT PRACTICES	ALTERNATIVE TECHNIQUES
DRILLING		
<u>Muds</u>		
Pollutant 1		
Pollutant 2		
Pollutant 3		
-		
-		
-		
<u>Reserve pits</u>		
Pollutant 1		
Pollutant 2		
Pollutant 3		
-		
-		
-		
PRODUCTION		
<u>Produced water</u>		
Pollutant 1		
Pollutant 2		
Pollutant 3		
-		
-		
-		

(and so forth for each major waste stream)

Figure I-12 Example matrix of pollutants and control/disposal methods to be constructed

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CHAPTER 3

ESTIMATING THE COSTS OF ALTERNATIVE WASTE MANAGEMENT PRACTICES

INTRODUCTION AND OVERVIEW

As requested under Section 8002(m)(F) of RCRA, this chapter of the report describes EPA's procedures for estimating the costs attributable to oil and gas field alternative waste management practices. Essentially, this involves estimating the incremental costs to oil and gas field companies of implementing increased levels of environmental control beyond the "baseline" practices currently employed in the various Regions and States. For the Report to Congress, these costs will be estimated at the individual project level for representative typical projects. Costs will also be scaled up to Regional and National totals as a basis for evaluating potential industry-wide impacts (see Chapter 4).

Procedures for estimating these costs involve a series of steps described briefly in the following paragraphs.

Step 1. Identifying Relevant Waste Management Practices

For cost estimating purposes, relevant practices include both standard waste management practices commonly employed in the various producing regions, as well as more advanced or sophisticated waste treatment, storage, and disposal methods that are potentially applicable but may be used less frequently or not at all in certain regions at present. A relatively complete array of such practices was described earlier in Chapter 2 of this report, and a selected representative group will be used in the cost study.

Step 2. Estimating Project-level Costs for the Selected Waste Management Practices

Engineering cost functions will be developed for the individual waste practices based on previous EPA cost modeling work, current industry literature, and selected industry interviews, as necessary. These cost functions for unit processes at various sizes will constitute the building blocks of the cost estimating methodology. Preliminary work and data sources for these basic costs are described in some detail following this introductory overview.

Step 3. Structuring Waste Management Scenarios

In order to have a consistent basis for evaluating costs, it is necessary to define all cost elements associated with each waste management alternative, both at the facility level and the aggregate industry level. Basically, the concept of the "scenario" is to hypothesize a given level of environmental control, typically a level beyond the baseline that is currently being achieved at some, or perhaps many, projects in a given region. This might be stated in terms of a set of waste-management technology requirements (such as present RCRA Subtitle C Standards) or in terms of specified conditions on environmental contaminant releases, or otherwise. Two or three such alternative scenario will be structured for purposes of the Report to Congress. Each scenario will clearly state both the types of waste characteristics relevant to the particular case and the control measures involved so that comparisons may be drawn between the costs of practices observed in the baseline profile and the costs estimated for the practices assumed in a given alternative scenario.

Step 4. Determining Affected Projects

Not all projects in a given Region or State will be affected by a given scenario for increased environmental control, either because the project does not generate "problem" wastes or because current practices (either naturally or because of current State or other Federal regulations) already meet the full requirements for the management scenario. This may be the case for entire States or multi-State Regions for a given scenario. The task here is to identify the proportions of total projects in all major Regions that would be affected and the degree to which they would be affected for particular waste categories. This is an essential step in generating reasonable cost estimates at the individual project level, and especially so in scaling costs to Regional and National aggregates.

Step 5. Calculating Project-level Cost Increases

Given the waste management cost functions for both baseline and alternative practices, together with information on Regional practices and affected facilities, "incremental costs" (increases incurred between baseline and improved alternative practices) will be calculated for representative Regional projects. (Regional differences are discussed in some detail in Chapter 4 in conjunction with economic impacts and the selection of typical representative projects.)

Step 6. Scaling Up to Regional and National Aggregate Cost Totals

The final step in the cost estimating analysis is to use information gathered from the industry-wide profiles of affected projects, together with the incremental cost estimates for representative projects, to calculate aggregate costs. Total investment costs, total annualized costs, and cost per unit of product (per gallon of crude oil or per MCF of natural gas) will be presented on both a Regional and National basis for comparisons. These aggregate costs, together with costs for representative projects, provide the basis for estimating the significance of any potential economic impacts due to changes in current practices. These economic effects are the subject of Chapter 4.

The remaining pages of this chapter provide further details on estimating methods and expected sources of data on cost functions and other work in progress.

ESTIMATION OF COSTS FOR INDIVIDUAL CURRENT AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

The purpose of this section is to discuss a limited number of representative disposal practices, such as the use of earthern pits (lined and unlined) and Class II (hazardous waste) injection wells, and to briefly describe how EPA will estimate baseline alternative management costs. The section also presents known or expected sources of information to support the cost analysis.

Cost estimates for other important current control and disposal methods not included here, such as waste solidification, landfarming, and incineration, which are described at length in Chapter 2, will also be analyzed as part of this effort.

Earthen Pit Storage and Disposal

Drilling wastes are commonly held in a reserve pit prior to disposal. Costs for disposal in lined or unlined evaporation or evaporation/percolation pits will be adapted from the general surface impoundment estimates from the EPA literature (U.S. EPA, 1985). These estimates may be adjusted, however, in recognition of possible difference between the assumptions of the EPA cost functions and actual oilfield practices. A more detailed discussion of current waste disposal practices is provided in Chapter 2.

Literature Review

The drilling cost estimates compiled annually by the American Petroleum Institute and the Independent Petroleum Association of America include a category covering road and site preparation. On average, road and site preparation represents 6.3 percent of total drilling costs (Independent Petroleum Association of America, 1986). Unfortunately, this category is too broad to allow identification of costs specifically for reserve pit construction. The costs for preparing the remainder of the site (other than the reserve pit) and for any entry roads commonly exceed costs for the reserve pit. Also, the specific technology represented in the disposal practices is not identified by the industry-average figures. Thus, unless more specific cost breakdowns can be developed from the original industry survey data, the published figures can be used only to describe an upper limit to disposal costs.

A few literature sources also give some indications of reserve pit construction costs (e.g., Rafferty, 1985). These estimates will be reviewed but will not be sufficient to provide the basis for estimating disposal costs.

Various cost estimates for constructing lined and unlined pits can be derived from previous EPA studies. Estimates of these costs are given in several sources (Charles River Associates, Inc., 1985, and U.S. EPA, 1985). Such costs will be reviewed for their applicability to the oilfield case. The costs are of the form $C = a V^b$ where C = cost, a = a constant, V = volume of water or capacity of the facility, and b = the elasticity of cost with respect to volume.

Data Collection and Analysis

Further cost analysis for construction of reserve pits will be developed using Means Site Work Cost Data 1986, a standard cost estimation source, and information to be provided by "dirt work" contractors. In the Means source, costs are presented for cut and fill operations, which are similar to the process of reserve pit construction. The unit costs for site work are given per cubic yard. These unit costs may be converted to total reserve pit construction costs using data on the capacity of reserve pits. The estimates derived using the Means source will then be verified and adjusted through discussions with firms engaged in site preparation work.

For closure of the reserve pit, the pit wastes are dewatered (by evaporation or vacuum truck removal) and backfilled. Costs for evaporation are incurred only when lease agreements with landowners are based on the amount of time the reserve pit remains in place. Costs for waste removal by vacuum truck will be derived through contacts with commercial oilfield waste removal firms. Costs for backfilling will be estimated using the reference source mentioned above, Means Site Work Cost Data 1986.

Disposal in Lined Pits (with Installation of an Impermeable Cap at Site Closure)

For this technology, clay or artificial liners from one to three layers thick would be installed in disposal pits to limit or prevent the release of leachate. In addition, an equivalent impermeable cap would be placed over the facility at closure to reduce infiltration from precipitation. This practice is primarily applicable to both drilling solids and associated wastes and to dewatered production sludges.

Literature review

Costs for liners and caps have been estimated in the models prepared by the Office of Solid Wastes (specifically, see U.S. EPA, 1985). Cost functions have been defined for surface impoundments using the following liner designs: single synthetic, double synthetic, single clay, single synthetic/clay, double synthetic/clay. The equations are of the form $C = a\ V^b$ where C = cost, a = constant, V = volume or capacity of the facility, and b = the elasticity of cost with respect to volume. The values for b vary from 0.6 to 0.7 in the EPA studies. Costs for facility caps are estimated in a similar fashion in these studies.

Data Collection and Analysis

The previous EPA studies will be used in estimating costs for facility liners and caps. The cost functions for various liner designs can be developed on a consistent basis from this source. Assumptions in the cost models about facility design, location, and soil characteristics that influence the costs for facility construction will be reviewed before the cost functions are used.

Monitoring and Site Management Practices

This includes components that are commonly required at permanent disposal sites. The elements include leachate collection systems, monitoring wells, runon/runoff systems, property fencing and site security, and provisions for post-closure maintenance of the facility.

Literature Review

Costs for each element of the package will be adapted from the previously estimated EPA cost models maintained by the Office of Solid Waste. Depending on the element, costs will be expressed as a function of the disposal volume or of the reserve pit dimensions.

Table I-15 presents cost functions estimated for basic monitoring and site management items in a previous EPA study. Economies of scale exist for leachate collection and treatment (the exponent in the equation for estimating capital costs is less than 1), but not for the other items.

Permitting costs may also be incorporated into this alternative. Costs for permitting activities will be derived from previous EPA studies covering the administrative and paperwork burdens of permit application. The costs will be based on estimates of the hours and personnel skill levels needed to prepare permit materials.

Data Collection and Analysis

Assumptions about the design and extent of the monitoring package will be adapted (with the costs) from the previous EPA estimates. Some adjustments must be made to account for the unique features of oilfield waste disposal facilities. For example, in comparison to landfills or

This page for I-15

Sample format of costs for monitoring & site mgmt.

surface impoundments that have been modeled in most EPA work, oilfield reserve pits are small disposal facilities. The capacity of the smallest surface impoundment in a recent EPA study is given as 638,307 gallons, or 14,300 barrels (U.S. EPA, 1985). This capacity would normally be adequate to handle wastes from a well drilled to deeper-than-average depth. Extrapolation of the cost estimates to allow analysis of smaller waste volumes will be necessary.

Offsite Disposal in a Secure Facility (i.e., Those Employing Multiple Liner Systems and Other Controls)

This disposal method is primarily applicable to most drilling and production wastes.

Literature Review

Costs for offsite solid waste disposal in secure facilities have been estimated by EPA and are included in the Liner Location Risk and Cost Analysis Model, Draft Report, (U.S. EPA, 1985). The estimates include costs for facility construction, operation and maintenance, and closure. The disposal facilities were designed with double or triple liner systems, leachate collection and monitoring provisions, and other control systems.

Alternatively, costs for offsite disposal might simply include charges made by commercial facilities, costs for waste management prior to shipping, and costs for transportation. The latter are described separately below. The disposal charges at commercial facilities have been presented in recent EPA studies (Industrial Economics, Inc., 1985, and Sobotka and Company, 1985). Table I-16 summarizes the estimates presented in recent publications. Most of the estimates were defined for broad categories of hazardous waste and are not specific to disposal of reserve pit wastes. Only the estimate presented in the Office of

TABLE I-16. Cost Estimates in Literature for Centralized Disposal

Type of Disposal	Bulk from Waste	1983 Prices (per MT)	Source
Landfill	Based on charges for bulk-form waste; transportation costs not included.	$28-$100	Booz, Allen & Hamiliton, 1984
Landfill[a]	Based on costs for low-risk hazardous waste (including drilling muds) disposal at commercial facility; transportation costs not included.	$125	Industrial Economics Inc., et al., 1985
Landfill[b]	Based on charges predicted for a captive facility plus profit estimates; includes 100-mile transportation charge.	$13-$29	U.S. Office of Technology Assessment, 1983
Surface *Impoundment*[b]	Based on charges for a captive facility plus profit estimate; includes 100-mile transportation charge.	$264.6	Industrial Economics Inc., et al., 1985

[a] These estimates are based on estimated operating costs for a captive facility (i.e., a facility owned by the waste generator) combined with an assumption regarding the profit level and transportation expenses.

[b] This estimate is based partly on figures compiled by Booz-Allen & Hamilton which are also referenced in this table. Thus, the estimates may not be fully independent from the other observation.

Technology Assessment study (Office of Technology Assessment, 1983) applies to low hazard wastes, such as most drilling muds.

Data Collection and Analysis

Price quotations for disposal at selected waste disposal facilities will be assembled to supplement the literature estimates for offsite disposal of reserve pit wastes. Some firms are currently receiving drilling solids, so their charges can be used directly in this research. For facilities that are not receiving such wastes at this time, estimates of charges for low hazard, bulk wastes will be considered most likely to represent the applicable costs.

Estimation of Waste Transportation Costs for Centralized Disposal

Oil and gas companies will incur incremental transportation costs whenever disposal alternatives require shipment of wastes off site or shipment of wastes to more distant sites than those currently used. The most significant transportation costs will be incurred for shipping of drilling wastes to centralized treatment facilities or pits and for shipping of production fluids for treatment and/or disposal in Class II wells.

Literature Review

Literature on hazardous waste disposal includes estimates of the cost per ton for waste shipments (e.g., Sobotka and Company, Inc., 1985). Many of the available estimates from EPA reports are derived from an earlier study of waste transportation costs (Abkowitz et al., 1984). This study provides a set of assumptions that may be used to derive estimates of the fixed and variable components of transportation costs.

Previous EPA studies have estimated mileage to specific hazardous waste disposal facilities by direct measurement of highway miles or by averaging distances from waste generators to disposal sites. EPA data bases are available to identify the location of the specific disposal facilities.

Data Collection and Analysis

Shipping costs for oilfield wastes are regulated in some States (e.g., Oklahoma) and such cost figures will be assembled. These regulated price limits and the other literature values may be a sufficient basis for estimating shipment costs per ton-mile.

To estimate the distances for transportation of drilling solids and associated wastes, an average distance will be calculated from the approximate middle of oil and gas basins to the nearest disposal facilities. This calculation will be made using maps of National oilfields and information on the exact highway location of disposal facilities. Depending on the volumes involved, new facilities dedicated to oil and gas waste disposal may be hypothesized for cost estimating purposes.

To estimate incremental transportation distances for drilling fluids and production fluids, a similar procedure will be used. Drilling fluids and production fluids may be shipped longer distances if necessary to reach Class I instead of Class II disposal wells. At present, Class II disposal wells are common in oilfield areas and transportation distances are relatively short. Class I disposal wells are much less common.

Estimates of current transportation distances (to Class II wells) will be developed based on a sample of current operations. Next, distances from the approximate middle of oilfield basins to specific Class I disposal wells will be estimated. Information on the location of Class I wells will be requested from State agencies or EPA Regions with responsibility for the UIC program. An average distance will be calculated for a sample of oilfield basins.

The transportation costs incurred by oil companies will be restrained to the extent that nearby disposal options eventually become cost effective. As transportation distances increase, for example, oil companies become more likely to drill new Class I wells in their producing fields. Relative costs of such options will be considered in the transportation analysis.

Class II Injection Wells

A common disposal method for most production liquids is injection in Class II wells. Produced water, however, may be injected for disposal only or it may be injected as a part of oilfield pressure maintenance efforts. A detailed discussion is provided in Chapter 2.

Literature Review

Costs for drilling new Class II injection wells were estimated in a 1979 study of the Underground Injection Control Program (Arthur D. Little, 1979). A range of estimates was given for wells drilled to depths of 2,000 and 5,000 ft. Since 1979, however, drilling costs have fluctuated widely. Therefore, current costs for drilling Class II injection wells will be obtained from drilling contractors.

Costs for various components of injection well operations are also addressed in the previous report (Arthur D. Little, 1979). The estimates, however, do not provide a complete profile of operating costs or disposal costs per barrel of produced water.

Data Collection and Analysis

Costs for injection for the purposes of disposal only are approximated by the prices charged at commercial disposal wells. Price information from these facilities will be obtained from a limited survey. Costs for injection in pressure maintenance (waterflood) operations are offset by enhanced hydrocarbon production. Effective costs for disposal may, therefore, be zero or negative depending on the effectiveness of the waterflood.

PLANS FOR ADAPTING EPA COST MODELS AND FOR ORIGINAL COST ESTIMATION

Many if not all of the baseline and alternative waste management practices described have been modeled, to some degree, in previous EPA studies. These models and other cost estimates found in the literature will be adapted where appropriate. Original cost estimates will be developed where necessary to supplement the previous results.

In preparing original cost estimates, source materials will include literature references, price quotations from vendors of waste treatment and disposal systems, and original engineering estimates as appropriate for each cost element. Cost estimation technologies to be used for this project include exponential cost functions, constant cost functions, and model case estimates, depending on the specific item under consideration. In most cases, exponential functions are most desirable for their flexibility in defining disposal costs for wells with differing waste volumes. For centralized disposal of drilling media and associated wastes, costs to the oil and gas industry are the prices charged by commercial waste disposal firms, plus transportation. Constant cost functions (e.g., a constant dollar-per-barrel price estimate regardless of waste quantity) have been used in much of the literature to characterize these prices. For this study, information on prices for bulk waste volumes (such as would apply to drilling solids) will also be sought. A constant or variable cost function will then be fitted to the cost data. Cost information for small volume wastes will also be obtained in order to establish a cost function for associated wastes (such as tank bottoms and separator sludges).

Identify Incremental Actions and Costs

Those operations required to alter their waste management practices (i.e., affected operations) under a scenario will incur incremental costs. The estimation of these incremental costs requires:

1. Identification of baseline waste management costs. The estimates generated in the analysis described above will be applied to establish baseline costs of the affected operations.

2. Estimation of incremental compliance measures. Based on the list of alternative waste management practices, the measures available to conform to the scenario will be identified, including incremental waste transportation actions.

3. Establish least-cost compliance method. In some cases, more than one alternative will be available for affected firms. By comparing the cost of available measures, a least-cost method can be identified.

4. Compare costs to baseline costs. Once the cost of waste management practices of affected firms have been estimated, these costs can be compared to baseline costs to establish incremental compliance costs.

The incremental cost estimates will be expressed initially as both capital investment costs and operating costs. The capital cost estimates will be annualized based on the expected life of the capital item and the industry discount rate. The cost estimates will be defined in terms of constant 1986 dollars, so the discount rate employed will reflect the industry's real cost of capital. For purposes of calculating annualized costs, typical project lifetimes must be estimated from available industry services.

Because there are so many oil and gas projects, the cost analysis described above must generally be performed on the basis of representative or "model" operations. In this case, model oil and gas operations will be defined to represent all of the firms affected under a given scenario. The identification of model facilities is described in more detail in Chapter 4.

Develop Regional and Aggregate National-Level Cost Estimates

The cost estimates for affected operations will be aggregated Regionally and Nationally to derive annual total costs for each waste management scenario. If model projects are used, National costs will be estimated by multiplying the model facility costs by the number of facilities the model represents.

Regional or National cost estimates will be two types. First, a National-level investment cost total will be generated. This is a sum of the investment costs (before annualization) for the affected projects. Second, a National-level annualized cost total will be generated by summing the total annualized cost to affected projects.

In addition to these National cost totals, other cost measures will be computed, including the environmental control cost per ton of disposed waste and the environmental control cost per barrel of oil or MCF of gas produced. The former can be used for comparison to the costs of other EPA hazardous waste management programs. The latter can be compared to the current cost of producing a barrel of oil to gauge the magnitude of the impact of a waste management scenario.

National-level costs will be developed for the period 1987-2000. Estimates of the level of growth of industry activity for 1987-2000 will be obtained from the Department of Energy/Energy Information Administration (EIA). The EIA mid-term forecasting system generates projections of oil and gas activity that are used in Federal energy planning.

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CHAPTER 4

IMPACT OF WASTE MANAGEMENT SCENARIOS ON PETROLEUM EXPLORATION, DEVELOPMENT, AND PRODUCTION

INTRODUCTION AND OVERVIEW

This chapter describes the scope and methods for EPA's analysis of the impact of alternative waste management practices on petroleum and gas exploration, development, and production, as called for in Section 8002(m)(G) of RCRA. The methodology for estimating the economic cost of alternatives is described in Chapter 3. The impact of these costs will be addressed for individual projects, on corporations and on the aggregate regional and national levels of industry exploration, development, and production.

The impact of incremental waste management costs will be analyzed first at the level of individual projects. Because of the large number of oil and gas projects initiated each year, "model" or representative projects will be defined. As described in detail below, model projects will be specified to capture regional differences in oil and gas development and to depict situations in which the impacts of the waste management scenarios are greatest.

Each model oil and gas development project will be characterized by a stream of expenditures and revenues. By estimating these expenditures and revenues and factoring these estimates into a discounted cash flow model, EPA will simulate the financial performance of model projects. A second series of model-project simulations will be run, incorporating the added costs of the alternative waste management scenarios for representative facilities. Comparison of financial performance under the different simulations will show the relative impact of the incremental environmental control cost on project financial performance.

The cost impact of the waste management scenarios will also be assessed at the industry and corporate levels. The total cost of the waste management alternatives will be compared to total annual industry investment and production expenditures to provide a broad measure of aggregate industrial-level impacts. To analyze impacts at the corporate level, the industrial-level cost of the waste management scenarios will be allocated to individual representative corporations. The decline in the financial ratios of these corporations due to incremental waste management expenditures will be calculated.

This chapter describes the methodology for the project-level economic impact assessment, corporate-level analysis, and the use of those results in formulating conclusions regarding the impact of environmental control costs on industry exploration, development, and production.

MODEL PROJECT ANALYSIS

Identification of Model Projects

The impact of the control requirements and costs on industry exploration, development, and production is essentially the sum of the impact on individual projects. An increase in waste management costs could potentially result in the early closure of existing projects or in the cancellation of new projects. If a large number of projects would be cancelled or curtailed under a given waste management scenario, then the level of industry exploration, development, and production would be reduced. Because the number of exploration and development projects initiated each year is so large (e.g., over 80,000 wells were drilled onshore in 1985), it is impossible to assess the impact of a scenario on a case-by-case basis; it is therefore necessary to depict "model" projects to represent the entire population.

Model projects will be defined for this research based on several criteria:

1. The model projects must represent the entire population; therefore, each model case must represent a substantial, identifiable part of the population.

2. The model projects must capture the impact of the waste management scenarios; therefore, some of the model cases must be selected to represent those situations where the largest environmental control costs (required under a scenario) will be incurred.

3. The model projects must depict situations in which environmental costs could affect overall project profitability; therefore, some of the model cases will depict economically marginal activities.

Establishing Representative Cases

Concerning the first criterion (i.e., representativeness), it will be necessary to depict model cases that capture the geographical diversity of the oil and gas industry. The regions of the country differ geologically, resulting in differences in mud formulations, drilling procedures, and production practices. These regional differences, in turn, bring about differences in the types of wastes generated, the waste disposal practices employed, and the overall cost and profitability of the projects. Model projects must be defined to capture these regional differences.

As described in a previous report (U.S. Environmental Protection Agency, 1986), the nation can be divided into 11 oil and gas Regions (Figure I-1). Regions 1 and 3 do not have a significant amount of oil and gas production. Thus, the model cases will focus on the other nine regions, with cases defined to capture regional characteristics of exploration, development, production, and waste generation and disposal.

Given the significant regional differences in the basic parameters of oil and gas projects, the nine regions will be used as a primary variable to distinguish model cases. Since the major industry data series present drilling and production information disaggregated to the State level (API, 1986; Independent Petroleum Association of America, 1986; DOE, 1986), these data can be used to specify the proportion of drilling and production that occurs in each region. These proportions can, in turn, be used to extrapolate the results of modeling within regions to the national level.

There will be significant differences, however, within regions concerning many of the parameters described above. Further, there are differences in the current regulatory treatment of these wastes, which lead to different baseline disposal practices and costs for the States within a region. Model projects defined using average regional values for the parameters will not capture these differences. It will, therefore, be necessary to specify additional model cases that depict situations in which the impact of the waste management scenarios will be greatest.

Environmental Control Costs

Subregional models will be defined to represent cases where environmental control costs will be highest. Projects depicting average regional characteristics may not experience significant environmental control costs under a given waste management scenario. However, some projects within the regions will experience significant costs. For example, if a scenario's environmental protection requirements lead to strict controls on oil-based muds, then model projects within Regions 4 and 7 must be defined to depict the use of such muds, even though the use of oil-based muds is not practiced by the majority of projects in the region. Further, projects in States with lenient current regulations may experience higher incremental costs, and such projects must also be modeled. Essentially, the requirements of a given waste management scenario are compared to baseline practices in each region. State and regional project profiles will provide the data necessary to extrapolate the results of the subregional models to the National level.

Marginal Economics Cases

Another critical factor determining the impact of a waste management scenario is the baseline economic performance of the model case. Those cases showing marginal economic performance in the baseline condition could be most affected by environmental control costs. Thus, as discussed further below, it will be necessary to specify marginal economic projects within the regions.

In summary, regional values will be used as a primary variable to identify model cases. However, "average" regional cases may have only limited interest to the analysis of a waste management scenario. It will, therefore, be necessary to specify subregional models to depict cases of high impact of environmental control requirements and marginal baseline economic performance.

Economic Parameters of Model Projects

Regional information, such as that presented above, will allow a project to be specified in technical terms. For example, a representative case in Region 2 would incorporate such features as air drilling, shallow depth, discharge of liquid waste, and a high gas-to-oil ratio. It will also be necessary to define the model cases in economic terms. The economic specification of model projects will allow a simulation of project financial performance both with and without the cost of environmental controls inherent in a waste management scenario. The following variables will be used to define model cases in economic terms:

- Drilling cost. Drilling costs will be derived from the Joint Association Survey on Drilling Costs (American Petroleum Institute et al., 1985). This source presents average drilling costs by depth category and by State. It can be used to derive average drilling costs for all specific model wells defined (by region or subregion) in the analysis.

  A new Joint Association Survey covering 1985 will be published in December 1986. Model inputs will be defined in 1986 dollars. To bring the survey cost estimates forward to 1986, extrapolations will be developed using more recent published drilling cost indices. Such indices are published by the Independent Petroleum Association of America and by the U.S. Department of Energy (Independent Petroleum Association of America, 1986, and U.S. Energy Information Administration, 1985b). At present, the published indices cover 1985, but the DOE index for 1986 will be published in January 1987. This index will then be used to adjust the region and depth-specific costs taken from the Joint Association Survey.

- Probability of a successful wildcat well. The probability of a successful wildcat well can be calculated from annual statistics on exploratory drilling as published in World Oil magazine. The data present the total number of exploratory wells and the number of oil, gas, dry and suspended (the drilling project was interrupted before its outcome was determined) wells by State each year. Thus the probability of a successful exploratory well can be calculated for each State, and subsequently for each region or subregion depicted in the model cases.

  Data are currently available (as of October 1986) on exploratory wells drilled through 1985. The 1986 data will be published in the February 1987 World Oil magazine. The success of exploratory well drilling over the past three years will be averaged for input to the model.

- Number of development wells per successful wildcat well. Oil companies who drill wildcat wells attempt to have surrounding acreage under their control. Should the wildcat be successful, the company can then derive the benefits of additional (i.e., development) wells. Thus the economics of a project are dependent upon the success of a wildcat well and the amount of development that results.

  The number of development wells completed per year is derived by subtracting the number of successful exploratory wells from the number of wells completed annually. The latter are presented in industry sources (American Petroleum Institute, 1986). The ratio of development to successful wildcat wells by region will be calculated and used as a parameter in the model projects.

- Operating costs. Operating cost data is compiled by the Energy Information Administration of the Department of Energy (Energy Information Administration, 1985a). Cost breakdowns are provided for categories of lease equipment and direct operating expenses by region and by depth categories. The regions and depth categories are, however, different in this source from the regions that have been defined herein. Thus, interpolation of the statistics will be necessary to match the operating cost data to the format needed for the economic modeling.

  Operating cost data through 1985 will be available for use in the model. Costs for 1986 will be extrapolated based on cost trends from historical data and from trends in other oilfield cost indices.

- Type of production. The type of production (i.e., oil, gas, or both) in each model is a statistic calculated directly from State oil and gas production figures. The type of production combined with current wellhead prices for oil and gas determine the project revenues. These statistics are available in major industry sources such as World Oil and the API Basic Petroleum Data Book (Gulf Publishing Co. and American Petroleum Institute, 1986). The State data will be combined as necessary to calculate the regional values for the type of production.

- Peak production level. Data on peak production are necessary for the effort to describe the amount of production and thus the revenue stream from successful wells. It will be assumed that peak production in all successful wells occurs in the first year. Thereafter, production is assumed to decline over time until the well is shut in.

  Data on initial production (IP) are available from State oil and gas commissions and from the Petroleum Information Corporation in Denver, Colorado. The initial production statistics will be compiled and averaged for each region in the study. It is anticipated that initial production averages will be calculated covering the past three years of production statistics.

- Production decline rate. The decline rate for production is needed to complete the profile of production and therefore to calculate the average revenue stream from successful wells. Hydrocarbon production typically declines over the life of a well, although decline rates are quite variable.

  Two possible approaches to development of this statistic are under consideration. First, a representative decline rate will be developed based on expert judgment obtained from industry sources and from Department of Interior, Mineral Management Services, publications.

  A second approach remains under consideration. In this approach, actual decline rates would be calculated from individual well records. A random sample of well records would be required for this task. The size of the necessary sample and other details of the calculation procedure have not yet been estimated.

- Wellhead selling price. The selling price for recovered hydrocarbons (in combination with the production profile) determines the revenue stream for oil and gas projects. Wellhead prices as of December 31, 1986, will be utilized in the modeling work. Wellhead prices are reported weekly in API publications.

- Tax treatment. A set of tax assumptions must be included in the model to allow calculation of the after-tax rate of return. The assumptions will approximate the national (i.e., all regions) tax treatment of oil and gas. Changes in the tax code included in the tax overhaul legislation passed by Congress in September of 1986 will be incorporated. Variations in State tax laws will be incorporated into the subregional models.

- Cost of waste disposal. Each model case would be characterized by a distinct waste disposal cost. Baseline waste disposal costs for the industry will be developed as described in Chapter 3. This baseline cost information will be adapted to the model cases.

Marginal Economic Cases

The preceding discussion has addressed methods for deriving economic parameters that define average or representative oil and gas projects. As mentioned previously, it will also be necessary to develop model cases of the marginally profitable projects in the industry. Such projects are most vulnerable to increases in waste management costs, and cancellation of such projects will impact industry production levels.

Projects may be marginal for a variety of reasons, including (1) location in areas that are characterized by small oil or gas reservoirs so that production levels are below industry average, (2) developments with high operating costs, such as where large quantities of produced water are generated and require disposal (e.g., stripper wells, waterflooding projects), and (3) developments by small companies that have higher hurdle rates (in other words, a higher cost of capital). Such firms may pay higher rates for debt financing than larger companies because of the greater risk to lenders.

Based on these and other factors, models of marginal economic cases will be defined for the analysis. The models will reflect intraregional variation in the economic variables described above. For example, some marginal cases will be based on patterns for initial production; that is, some cases will be defined for those areas characterized by low initial production (and, therefore, modest revenue streams during the life of the project).

Model Project Simulations

The economic parameters of the model projects will be input to a discounted cash flow model designed by EPA to simulate the financial performance of oil and gas projects. The economic model simulates the performance and measures the profitability of model projects. For each model project, exogenous economic data (e.g., drilling cost, number of development wells, production rate, wellhead selling price) are input to the economic simulation model. The model calculates the annual after-tax cash flow for each year of project operation, as well as cumulative measures of a project's performance such as net present value (NPV) and internal rate of return (IRR).

The EPA economic model software provides integrative calculation procedures and algorithms that duplicate (1) the oil industry's accounting procedures, (2) standard rate of return calculation methods, and (3) Federal taxation rules. The tax code revisions enacted by Congress in September 1986 are now being incorporated into the model.

Each model project will be simulated in a base case and under the requirements of each waste management scenario. The base case simulation will, simply, operate the model incorporating baseline economic values to calculate a model project's economic performance. The alternative cases will incorporate the same economic information and the additional cost of the waste management scenario to estimate a new (lower) NPV and IRR for each model. Costs for the waste management scenarios will be developed as described in Section 6.4. The national-level cost analysis in Chapter 3 will employ the same model cases as the impact assessment described here, so the cost information developed in that chapter can be adapted directly for use in the model project simulations.

The baseline economic results will be compared to the economic results under a waste management scenario as a first measure of regulatory impacts. The issues addressed in this comparison include the following:

1. Absolute decline. The absolute decline in internal rate of return under a given scenario for each model project will give an immediate indication of economic impact. If the decline is less than one tenth of a percentage point for all models, for example, impacts will not be severe.

2. Hurdle rate. A second indication of impact is whether the incremental waste management costs push any of the model projects from a level above the industry hurdle rate of return to a level below that rate. If the decline in IRR makes some model projects unprofitable, impacts could be substantial.

CORPORATE AND INDUSTRY-LEVEL IMPACTS

Another way to measure the impact of regulatory costs of exploration, development, and production is to compare annual compliance expenditures to annual corporate and industry investment expenditures. These comparisons can give a good initial indication of whether regulatory costs are likely to have a substantial impact on industry capital formation.

Industry-Wide Assessment

Total aggregate annual costs will be estimated for each waste management scenario as described in in Chapter 3. Total industry investment expenditures are compiled and published annually by the Energy Economics Division of the Chase Manhattan Bank. This source tabulates all industry exploration and development expenditures, both onshore and offshore. By dividing the total annual costs under a given regulatory scenario by total annual industry expenditures for exploration and development, one can obtain a first measure of the magnitude of effects on industry investment spending.

EPA will compare the cost of each waste management scenario to industry-wide exploration and development expenditures in four separate ratios:

1. Annual Incremental Expenditures Under a Given Waste Management Scenario (as described in Section 6.4)/Total Annual Industry Exploration and Development Expenditures (Chase Manhattan Bank).

2. Annual Incremental Expenditures Under a Given Waste Management Scenario/Total Annual Industry Onshore Exploration and Development Expenditures.

3. Annual After-Tax Expenditures Under a Given Waste Management Scenario/Total Annual Industry Exploration and Development Expenditures.

4. Annual After-Tax Expenditures Under a Given Waste Management Scenario/Total Annual Industry Onshore Exploration and Development Expenditures.

Each of these ratios provides a slightly different comparison. The use of onshore expenditures as opposed to total industry expenditures allows waste management costs to be compared to the subset of industry expenditures that the compliance expenditures would be part of. The use of gross compliance expenditures in the numerator (Ratios #1 and #2) compares the social cost of compliance to total industry exploration and development expenditures. However, industry will deduct compliance costs as business expenditures and will, therefore, not pay the entire social compliance cost. The use of after-tax compliance costs in the numerator (Ratios #3 and #4) compares the cash effect of compliance to total industry expenditures. These latter ratios, then, provide a measure, from the industry's point of view, of the percentage of funds diverted from other uses to pay for regulatory controls.

Financial Assessment for Representative Companies

In addition to the above industry-wide ratios, a second set of ratios can be calculated to show the impact of compliance costs of the financial health of individual corporations. Using financial data available from corporate annual reports, EPA will construct a representative balance sheet for a typical major, a typical large independent, and a typical small independent oil company. These balance sheets can be used to calculate statistics and ratios which measure a company's financial health.

EPA will use four financial parameters in the analysis: level of working capital, current ratio (i.e., current assets divided by current liabilities), long-term debt-to-equity ratio, and debt-to-capital ratio. These parameters will be calculated both before and after the incremental cost of a waste management scenario. Parameter calculations under the waste management scenarios will be calculated under two sets of assumptions. The first assumption is that incremental waste management costs are funded out of working capital and, therefore, the level of working capital and the current ratio will be impacted. The second assumption is that incremental waste management costs are funded out of long-term debt, and therefore, the long-term debt-to-equity ratio and the debt-to-capital ratio will be affected. A comparison of pre- and post-scenario ratios will provide an indication of the financial effect of the scenarios on a corporation-specific basis.

In the above analysis, the fraction of total industry compliance costs attributed to the model major and the model independent oil companies will be estimated by comparing the exploration and development expenditures of the model corporation to those of the industry as a whole. In a related study, EPA estimated that a typical major accounts for 5.4 percent of industry exploration and development expenditures while a typical independent accounts for 0.3 percent of all such expenditures. Thus, for the ratio analysis described above, it will be assumed that 5.4 percent of total aggregate compliance costs (as calculated in Section 6.4) are borne by a typical major and that 0.3 percent of aggregate compliance costs are borne by a typical independent oil company. Small companies in areas experiencing the greatest impact of the regulatory scenarios, may absorb more than a proportional share of the national costs. For these firms, modified assumptions regarding the actual (larger) share of national costs to be borne will be developed for the ratio analysis.

IMPACT ON INDUSTRY EXPLORATION, DEVELOPMENT, AND PRODUCTION

The analysis will provide several indications of the economic impact of the costs of the alternative waste management scenarios. In particular:

1. The financial impact of the environmental control costs will be simulated for representative projects, including average projects, projects expected to show the largest total costs, and for projects showing marginal baseline economic performance.

2. Incremental costs under the waste management scenario will be compared to total industry onshore exploration and development costs.

3. Incremental costs under the waste management scenarios will be compared to total industry exploration and development costs.

4. The financial ratios of typical small independent, large independent, and major oil companies will be estimated separately, both before and after the costs of the waste management scenarios are estimated.

EPA will evaluate these results to determine whether any of the waste management scenarios will have a substantial impact on industry exploration, development, and production. Three key issues will be addressed. First, a determination will be made as to whether any (and what percentage of) projects would likely be cancelled under each waste management scenario. Second, a determination will be made as to whether any of the waste management scenarios will affect the industry's ability to raise capital. Third, the results of the ratio analysis will be reviewed to determine whether the ratios of any affected firms will deteriorate to the point where the probability of financial failure increase significantly.

Because oil is sold in a world market with abundant foreign supply at the world price, any decrease in domestic exploration, development, and production will lead to an increase in imports. These balance of trade effects will be estimated. It is not expected that the waste management scenarios will result in production declines substantial enough to change price in the world market, so fuel substitution and the rate of development for alternative energy technologies will not be affected.

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Part II

Geothermal Energy

CHAPTER 1

INDUSTRY DESCRIPTION

The purpose of this section is to provide background information on geothermal energy and a profile of the geothermal energy industry. This report presents a brief description of geothermal energy systems; where geothermal energy systems are found, some common techniques used by industry for bringing the resources into production, and a discussion of how the resources are used.

BACKGROUND

The crust and the atmosphere of the earth account for less than one-half of a percent of its total mass. The remaining 99.5 percent lies concealed beneath the crust, and our knowledge of the nature of the material beneath the crust is largely a result of the study of earthquake waves, and lavas, and measurements of the flow of heat from the interior towards the surface. Nevertheless, this indirect knowledge has allowed us to construct a fairly clear and consistent model of the structure of the earth. The currently accepted structure consists of four concentric spheres; from the outermost to the innermost they are the crust, the mantle, the liquid core, and the innermost core, which is believed to be solid. This structure is presented in Figure II-1. Temperatures and densities rise rapidly as the center of the earth is approached. The term "geothermal energy" is defined by some to include all of the heat contained in these four concentric spheres (approximately 260 billion cubic miles that constitute the entire volume of the earth) (Chilinger, et al., 1982). The potentially useful part of this enormous energy supply, however, is represented by that small fraction of the earth's volume in which crustal rocks, sediments, volcanic deposits, water, steam, and other gases at usefully high temperatures are accessible from the earth's surface and from which it may somehow be possible to extract useful heat economically. Even this small portion of the total is an enormous reservoir of thermal energy. The classification, location, and recovery of this portion of the available thermal energy are the subjects of this section.

THE NATURE AND OCCURRENCE OF GEOTHERMAL ENERGY SYSTEMS

Geologists and engineers classify geothermal energy systems into three major categories:

- Hot igneous systems;
- Conduction-dominated systems; and
- Hydrothermal systems.

The first two categories may contain the largest amount of useful heat energy, but are not economically and technically feasible to exploit. Advancements in current technology would be required in order to use these potential heat sources commercially. The third category, hydrothermal energy systems, is commercially viable and has received the most attention because extraction technology exists for the economic recovery of heat from these resources.

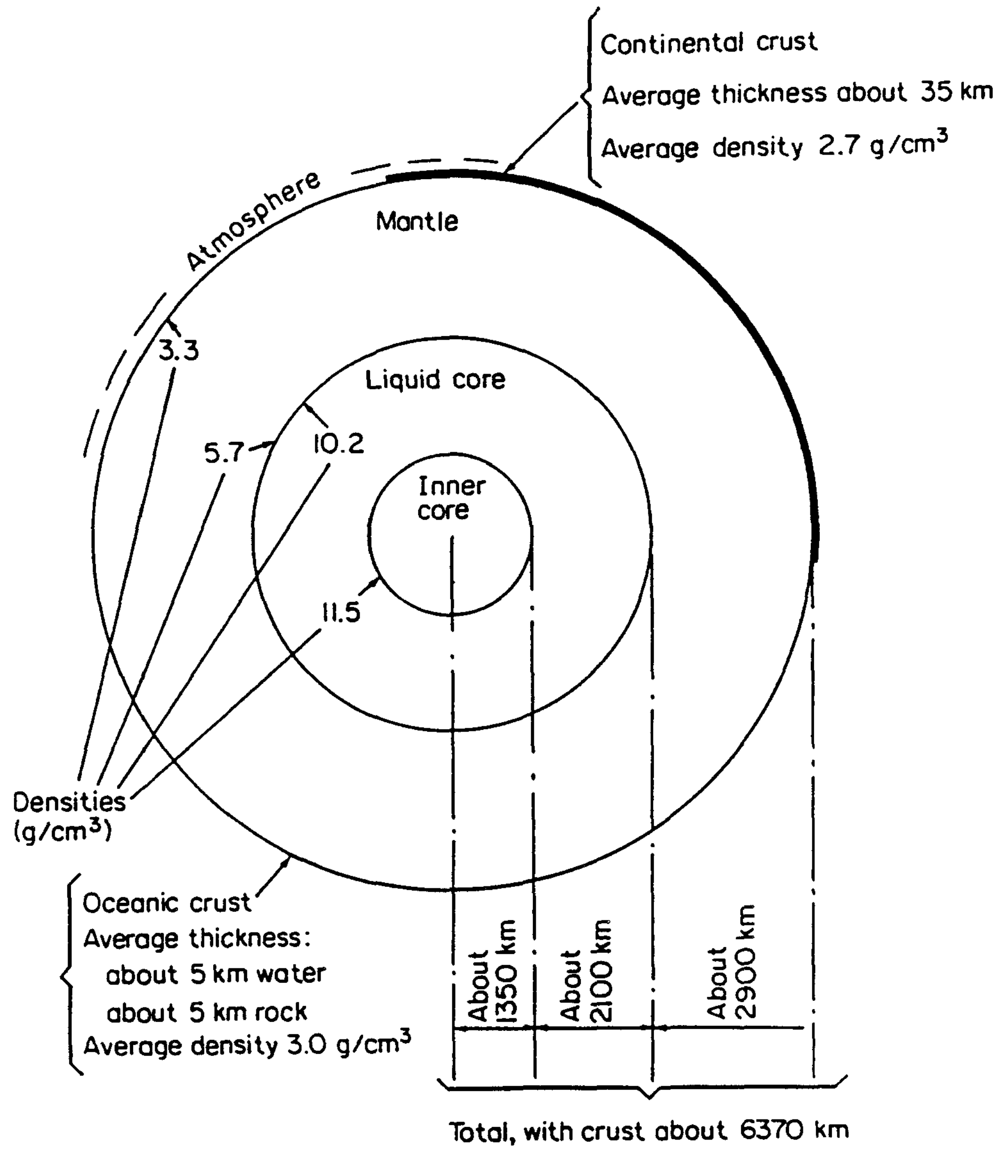

Figure II-1. Concentric Layers of the Earth.

Source: Armstead, Christopher H., "Geothermal Energy: Its past, present and future contributions to the energy needs of man," 2nd Ed., London, 1983, E and FN Span.

Hot Igneous Systems

These systems consist of magma chambers near the earth's surface that are created by the buoyant rise of molten rock generated deep in the earth's crust. This type of geothermal energy system is made up of two major groups: Hot, Dry Rock, where the magma is no longer molten (less than 650°C), and Volcanic Systems, where the magma is still molten or partly molten (greater than 650°C). Figure II-2 presents a schematic diagram of a representative hot igneous system.

Because of the great depth (3 km) and high temperatures (650-1200°C) associated with volcanic systems, the heat is not recoverable with current technology. The hot, dry rock - hot igneous systems, however, are located on the margins of molten magma chambers and might in the future be favorable candidates for recovering heat energy. Some speculate that a system of hydraulic fractures can be created between special, directionally-drilled wells to provide circulation loops in rocks having low to very low permeability. An experimental program at Los Alamos, New Mexico, is underway to develop this technology. Success in these efforts will make it possible to consider exploitation of hot dry rock geothermal energy. In general, however, the economic extraction of energy from this resource has yet to be demonstrated (Chilinger et al., 1982).

Conduction-Dominated Systems

The very high heat from the molten center of the earth is transferred very slowly from deep within the earth to the surface by thermal conduction. Because of the size and relatively low heat flux at or near the surface, however, one would have to drill 5 to 10 km to reach subsurface temperatures of only 100°C. Therefore, the development of this

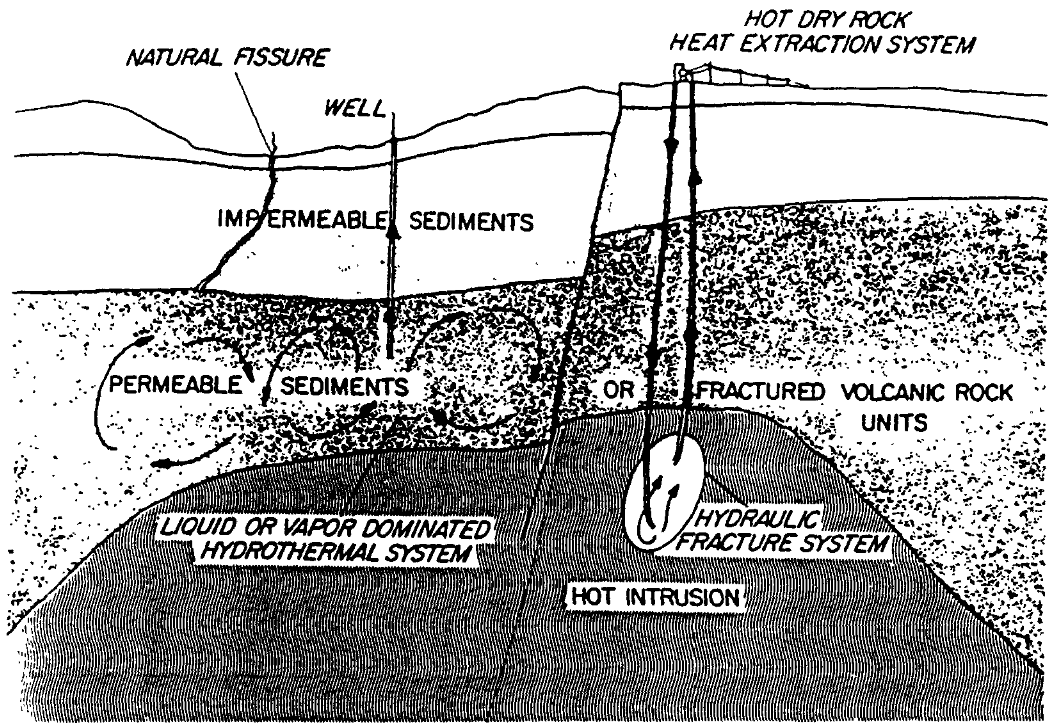

Figure II-2. Schematic Diagram of a Hot, Dry Rock Geothermal System.

Source: Chilinger, G.V., L.M. Edward, W.H. Fertl, H.H. Ricke III, Editors, "The Handbook of Geothermal Energy." Houston, Texas, 1982, Gulf Publishing Company.

type of system is not, at this time, economical. Geopressured reservoirs are also within this category, however. Geopressured reservoirs are usually found in deep sedimentary basins where a lower level of sediment compaction has taken place over geologic time and where an effective caprock exists. These conditions, supplemented by water released, possibly by clay mineral alteration, foster trapped-water pore pressures up to several thousand pounds per square inch above the hydrostatic pressures that would normally exist. For example, temperatures up to 237°C with wellhead pressures in excess of 11,000 psi have been recorded in some geopressured zones in the States of Texas and Louisiana (Chilinger et al., 1986). Since there is no deep circulation of the water, however, it only reaches moderately elevated temperatures. Because these reservoirs are usually associated with petroleum, the water is generally saturated with methane and other hydrocarbon gases. They therefore could represent an important supplement to the supply of natural gas. There is still no direct evidence that heat, natural gas, or both can be extracted economically from geopressured hot water reservoirs, but large-scale field experiments are now underway to investigate this possibility.

Hydrothermal Systems

Hydrothermal systems are the systems of economic importance. These systems consist of high temperature water and/or steam trapped in porous and permeable reservoir rocks. Because of the convective circulation of water and steam through faults and fractures, the heat is transported to near the earth's surface. Gravity is the driving force of this movement, owing to the density difference between cooler, downward moving water and the hot, upward moving water. The heat that is available in the geothermal reservoir rock is produced by bringing hot water and/or steam to the surface. Figure II-3 presents a schematic diagram of a simplified hydrothermal system.

Two classes of hydrothermal reservoirs exist. Reservoirs that liberate mostly steam are referred to as vapor-dominated. Liquid-dominated reservoirs are reservoirs where the water is in the liquid phase; they are much more abundant and are usually found in permeable sedimentary rock. The latter reservoirs are also found in competent rock systems, such as volcanic formations, if open channels along faults or fractures exist. A brief discussion of both systems is presented below.

Vapor-Dominated Reservoirs

If the caprock in a hydrothermal reservoir is not able to sustain the pressure level to prevent boiling, then pockets of steam will form. When the pressure is relieved (for example, by drilling a well into the pocket), most of the dissolved minerals are left behind in the formation, and relatively pure steam is recovered. Except for a variable content of noncondensible gases (which could be methane, carbon dioxide, radon, and hydrogen sulfide) the evolved steam can be an economical energy source. Frequently, it is used to drive turbines and generate electricity.

The existence of a large, bounded volume of rock within which temperatures are high enough and pressures are low enough to permit boiling within the cavity is rare. Therefore, vapor-dominated systems or natural steam reservoirs are far less common than hot water reservoirs. Nevertheless, the technology for utilizing energy from vapor-dominated systems is well developed, and one of the largest geothermal power plant developments in the world (at The Geysers in California) uses steam from such a system (Chilinger et al., 1982).

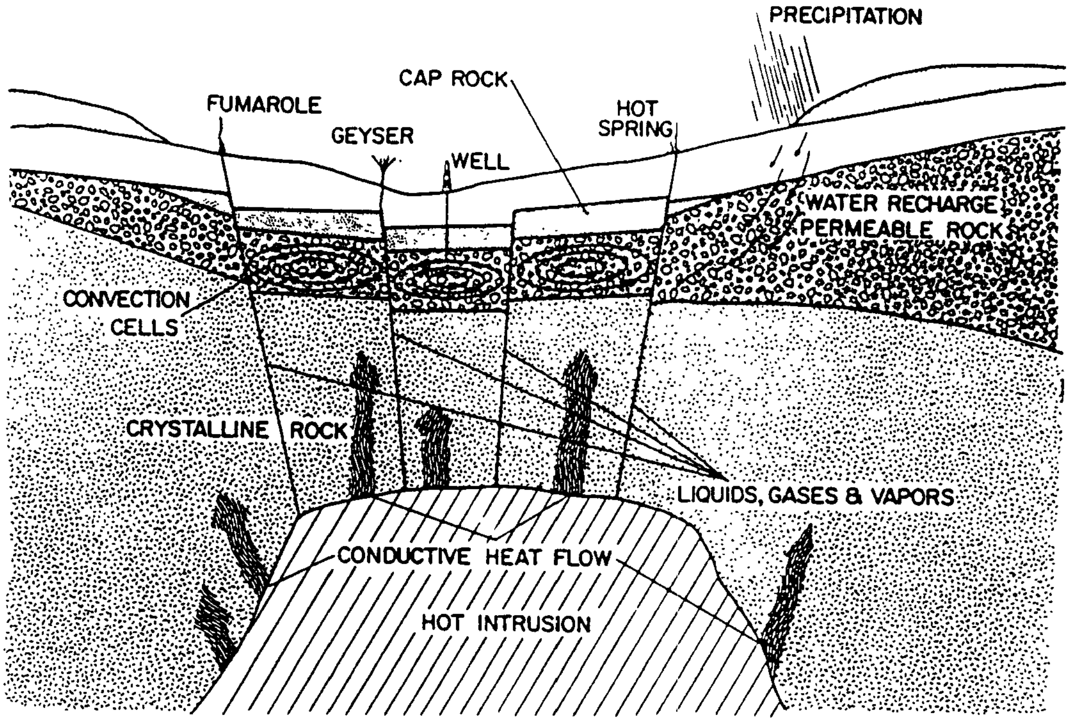

Figure II-3. Diagram of a Hydrothermal Geothermal Reservoir.

Source: Chilinger, G.V., L.M. Edward, W.H. Fertl, H.H. Ricke III, Editors, "The Handbook of Geothermal Energy." Houston, Texas, 1982, Gulf Publishing Company.

Power generation from these resources produces relatively small quantities of solid wastes. This is primarily due to the nature of the vapor transport mechanism that carries the volatile components to the surface. Some secondary waste components, however, are generated from use of the vapor or off-gas cleanup systems employed in the overall process. These solid wastes could include significant levels of hydrogen sulfide, boric acid, arsenic, and mercury (USEPA, 1978).

Liquid-Dominated Reservoirs

In these reservoirs water slowly circulates through permeable crustal rocks, encounters rock at high temperatures, and, becoming less dense as it is heated, rises buoyantly toward the surface. If some geologic barrier prevents it from actually reaching the surface, an underground reservoir may form, within which the water will circulate convectively. This slow circulation of the water allows it to continuously extract enough heat from the lower part of the reservoir to compensate for the heat that escapes upward through the formation. Thus, an equilibrium may eventually be reached in which the water temperature throughout the reservoir is approximately uniform (this temperature may range anywhere from slightly above ambient temperature to 350°C or higher).

Hydrostatic pressure on the water is usually high enough to keep it from boiling even when the water is greatly superheated. Because of its high temperature and its residence time in the reservoir, the water becomes saline and can be saturated with the minerals with which it comes in contact. Since the solubilities of a number of minerals increase with temperature, the hotter geothermal waters generally contain greater contents of dissolved solids than water at ambient temperature. This condition is, however, strongly site-dependent, because the mineralogical composition of the rock of a geothermal reservoir varies widely from site to site. As a rule, the concentration of metals and other constituents also increases as the concentration of total dissolved solids increases (USEPA, 1978).

Geothermal liquids range rather widely in hydrogen ion concentration, with pH values generally between 2.0 and 8.5 (USEPA, 1978). It appears that most liquids are above a pH of 7.0. Liquids of higher salinity generally have the lowest pH and can be highly corrosive to man-made materials.

Noncondensible gases, those that do not condense at normal ambient operating temperatures, are environmentally important constituents of geothermal liquids. They may be free gases, dissolved or entrained in the liquid phase. Hydrogen sulfide traditionally has been the component of greatest concern. Noncondensible gases usually comprise between about 0.3 percent and 5 percent of flashed steam from geothermal liquids (USEPA, 1978).

Radioactive elements are also generally found in geothermal liquids in low concentrations. These include uranium and thorium isotopes, radium, and radon. Radon, a radioactive gas and one of the products of radium decay, is the most significant generally recognized radioactive component in geothermal liquids. EPA data covering 136 geothermal sites showed a range of 13 to 14,000 pCi/l (picocuries per liter), with a median of about 510 pCi/l (USEPA, 1978).

Chemicals, such as acids, bases, and various flocculants and coagulants, may be added to geothermal liquids to minimize scaling and corrosion or to remove certain constituents. Although these chemicals may not in themselves be of great consequence as pollutants, consideration must be given to interactions that might alter the geothermal liquid composition. This is particularly true of any metal compounds which may be added during this process. Most such chemicals will be acids and/or bases used for pH adjustment.

The Geographic Distribution of Geothermal Energy Systems

The locations of hydrothermal and geopressured resource areas are shown in Figure II-4. Identified hydrothermal systems with temperatures greater than or equal to 90°C are located primarily in the western United States, while low temperature geothermal waters are found in the central and eastern United States.

EXPLORATION OF GEOTHERMAL RESOURCES

Preliminary Exploration

The overall objective of any geothermal exploration program is to locate a geothermal resource system from which energy can be profitably extracted. Rapid low-cost reconnaissance techniques are employed in the early stages of exploration, when gross areas are to be screened for commercial potential. For example, leakages of liquids through the impermeable capping often occur in natural geothermal systems. These leaks and/or seeps may produce such features as fumaroles, hot springs, warm springs, geysers, mud volcanoes, or boiling ground, and are the most direct and obvious indicators of the presence of a geothermal reservoir or system. These seeps can also provide quantitative information on the nature of the reservoir and the liquids contained within it.

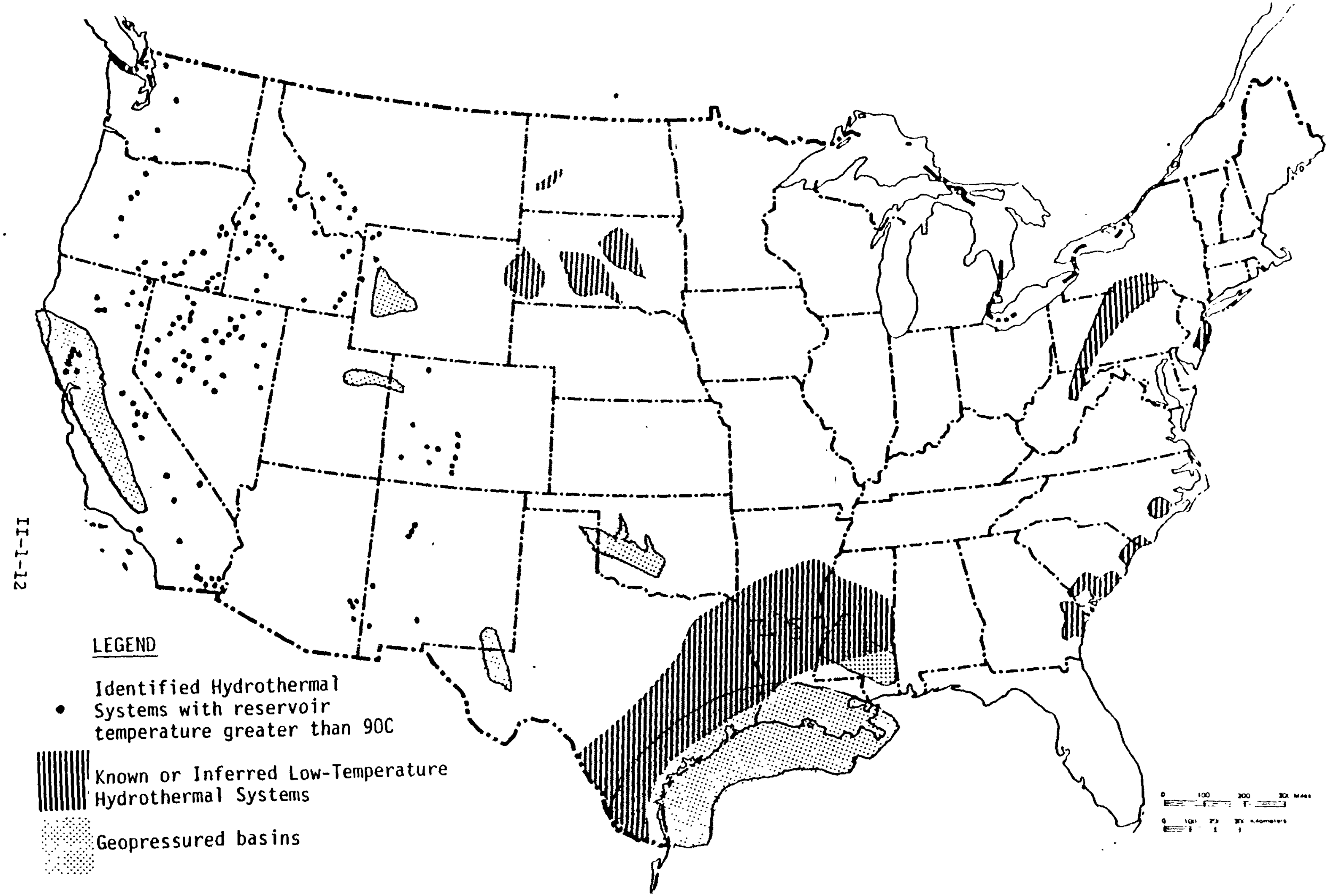

Figure II–4 The Geographic Distribution of Geothermal Energy Systems

Geothermal Well Drilling

Exploratory drilling is undertaken once an area is defined. This allows the exploration area to be narrowed to confirm the existence of a production field.

The drilling of geothermal wells is quite similar to the drilling of oil and gas wells. The major differences between geothermal and oil and gas wells have been described in the literature (Armstead, 1983). They are the following:

- Nearly all geothermal well drilling is performed at relatively low pressure (this excludes the geopressured geothermal testing now underway in the Gulf Coast area).
- With the exception of the Gulf Coast area, the majority of the geothermal wells are of relatively shallow depth (1,500 m), having high formation temperatures.
- The rocks being drilled are mostly igneous and metamorphic.
- Geothermal wells are usually 50-100°C hotter than oil and gas wells of comparable depths (Armstead, 1983).
- Cooling towers are sometimes required for the geothermal drilling fluids.
- Gas/drilling fluid separation is sometimes required for geopressurized field drilling.

In fields that produce water exceeding 100°C, the drilling depth usually ranges from about 500-2,000 meters, and although a few bores may lie outside of these limits, the majority lie in depths of 600-1,500 meters. In lower temperature fields and in low grade aquifers depths of approximately 1,800 meters are common, but in some places (e.g., Klamath Falls, Oregon), where the aquifer is located close to the surface, wells range from 30 to 300 meters. In geopressured fields, depths of about 6,000 meters may be necessary (Armstead, 1983).

Nearly all geothermal wells have been drilled using the rotary drilling technique. A typical rotary drilling rig is shown in Figure II-5. Before the drilling operations can be initiated, a concrete cellar must be constructed. The cellar serves to support the weight of the drilling rig and accommodate the wellhead valving and is generally accessed by a concrete stairway. Consolidation grouting is usually injected into the surrounding ground. This grouting provides additional support and serves to deflect away from the wellhead any steam that may accidentally ascend to the surface along the outside of the bore and its casings (Armstead, 1983).

The methods and equipment used for geothermal drilling do not vary greatly from those used in petroleum and natural gas drilling. Both rotary and turbo drilling can be used. In geothermal well drilling, however, because of the possibility of encountering harder rock formations, higher temperatures, and highly corrosive fluids, certain modifications in techniques, materials, and equipment are required. (Armstead, 1983) Serrated tri-cone drill bits made of very hard steel are used to effect penetration. The drill bits are attached to a hollow drill stem, and both are rotated by a power source, which is usually a diesel engine (Armstead, 1983).

The process of drilling for geothermal steam is a complex process. A tall lattice steel tower, which contains a pulley system, is used to position and withdraw the drill stem and the casing. Power units are also needed for rotating the drill, operating the derrick, and driving the auxiliary pumps and compressor. There are racks for carrying a stock of such items as casing pipes and drill stems, and a circulatory system for pumping, cooling, screening, settling, and storing the cooling mud (Armstead, 1983). This circulating system, and its cooling fluid (mud) are of primary concern since it is responsible for generating one of the major waste streams.

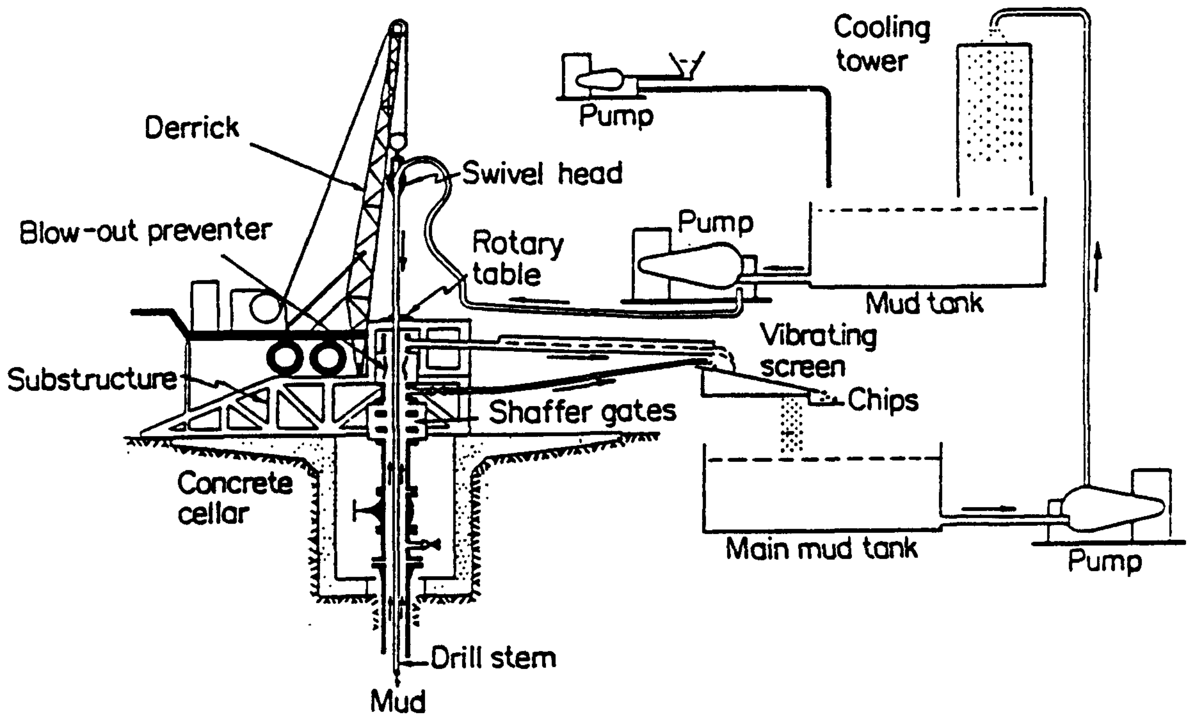

Figure II-5. Typical Rotary Drilling Rig and Mud Circulation Arrangements.

Source: Armstead, Christopher H., "Geothermal Energy: Its past, present and future contributions to the energy needs of man," 2nd Ed., London, 1983, E and FN Span.

One of the most important factors in drilling is the provision of adequate steel casings. Normally, up to four concentric casings may be installed in a single well. They are constructed of high quality steel and are rigidly fixed with cement to the surrounding rock. The purpose of the casing is to prevent the collapse of a newly drilled, completed well. Figure II-6 presents a diagram of a completed hydrothermal well with installed casings.

Drilling Fluids (Muds)

The primary purpose of the drilling fluid is to cool and lubricate, and to flush out rock chippings from the bore hole. It also serves to prevent collapse of the bore walls and to cool the surrounding ground. The fluid is pumped downward through the hollow drill stem and returns upward through the annular space surrounding it. The mud circulates from the bore, is screened to remove rock cuttings, and is then passed through a cooling tower. A cooling tower may not always be needed and the need for one depends upon the downhole temperatures (Armstead, 1983).

The type of drilling fluid used and its proper control are essential in geothermal drilling operations. The drilling fluid used for both the vapor-dominated and liquid-dominated systems may be similar. However, drilling into vapor-dominated systems generally utilizes air so as not to kill the production zone with a hydrostatic column of fluid. Liquid-dominated systems are normally drilled with conventional drilling fluids (muds). Various types of drilling muds may be used and the type and composition of the mud depend upon the drill-site conditions. Some of the more common drilling fluid systems are listed in Table II-1.

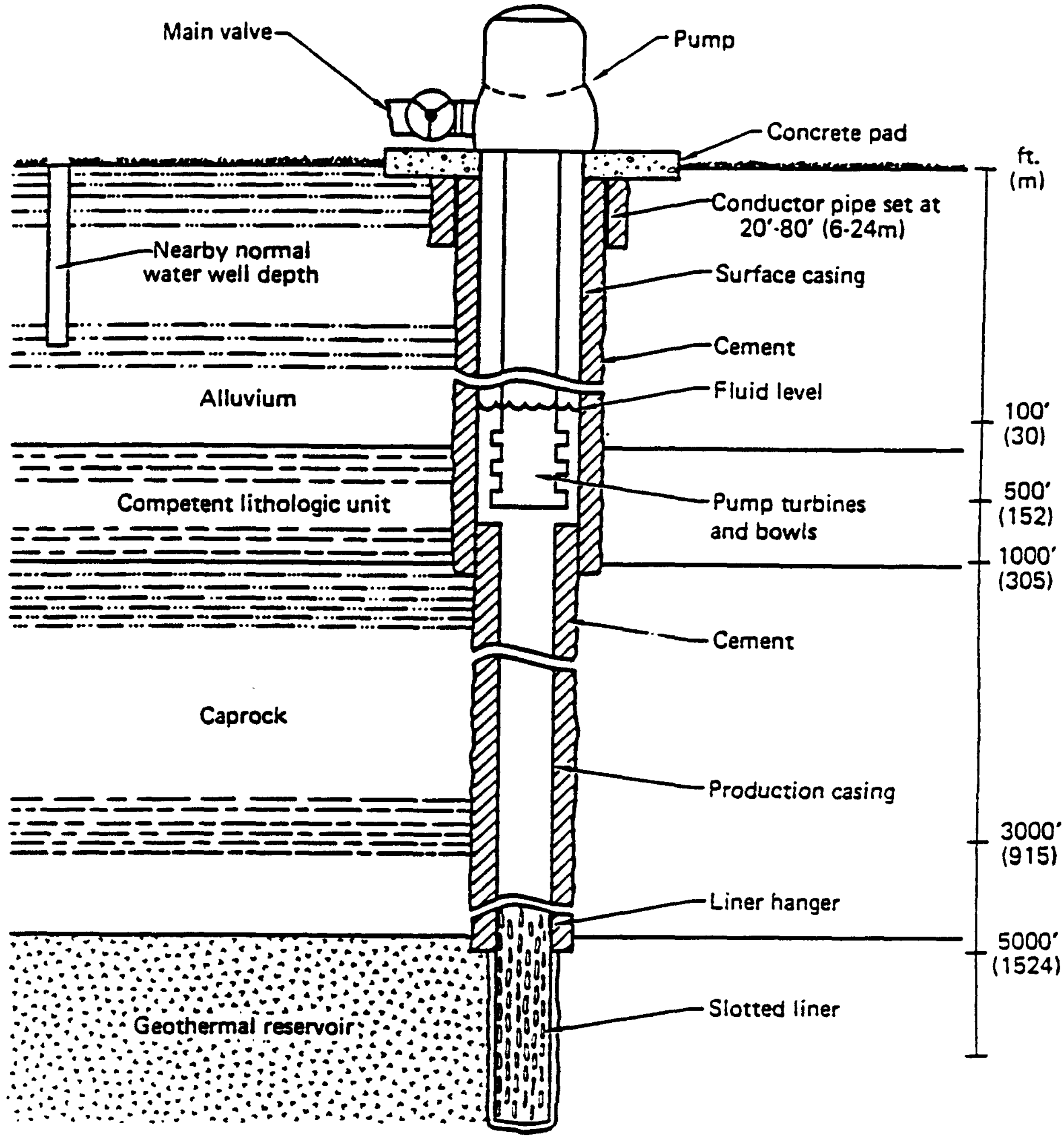

Figure II-6 Cross Section of a Typical Hydrothermal Well (not to scale).

Source: O'Banion, K. and D. Layton, "Direct Use of Hydrothermal Geothermal Energy: Review of Environmental Aspects," U.S. Department of Energy, April 1981.

Table II-1. Common Drilling Fluid Systems Prevalent in Geothermal Drilling

Type	Composition
Bentonite water	Bentonite provides viscosity and fluid loss control with NaOH addition for pH adjustments.
Bentonite lignite - caustic soda system	Lignite is incorporated in the fluid to provide greater thermal stability and better viscosity and fluid loss control than a simple bentonite water system.
Chrome - lignite - chrome lignosulfate system	Chrome lignite and chrome lignosulfate are added to the drilling fluid to impart greater overall stability.
Polymer system	Predominantly composed of polymers. This results in bentonite extension and flocculation of drill solids, thus creating a low solids, mud system.
Sepiolite system	Sepiolite clay is substituted for bentonite because it does not flocculate at high temperatures and provides better viscosity control. Modified polymers are added for fluid loss reduction and caustic soda for pH adjustment.

Distribution of Geothermal Drilling Activity

Table II-2 and Figure II-7 present data on the locations of current major geothermal drilling activity in the United States from 1976 to 1978 (Chilinger et al., 1982). This activity is mainly found in the western United States where hydrothermal resources tend to be located.

ELECTRICAL POWER GENERATION

There are basically two processes that can be used in the generation of electrical power: the conventional steam cycle and the binary power system.

In the conventional steam cycle, geothermal brine is partially converted to steam by flashing or sudden pressure reduction in a vessel. Steam from the flash process system is then piped to the manifold where it is used to directly power a turbine generator. The exhaust steam from the turbine is condensed on a surface or barometric condenser. The noncondensible gases are vented to the atmosphere using a steam injector system. The condensate is then pumped to a cooling tower where it can be cooled and reused as water or, more typically, reinjected into the aquifer. Figure II-8 presents a flow diagram for this type of process (USEPA, 1978).

In order to maximize thermal efficiency, some cycles utilize multiple flashes in the overall process scheme. Because the brine usually includes high levels of dissolved solids, the concentration of solids in the brine increases in each flash cycle and the brine becomes more corrosive. Therefore, a flash injection system may not be economically used in geothermal energy fields containing a high concentration of dissolved solids (USEPA, 1978).

Table II-2. Summary of Major Geothermal Drilling Activity in Western U.S.A. (1976-1978)

State	Region	Area	Number of wells 1976	1977	1978	Total
California	Imperial Valley	Westmorland	6	1	-	7
		Brawley	2	2	4	8
		East Mesa	2	5	7	14
		Salton Sea	-	-	1	1
		Heber	6	-	-	6
		South Brawley	-	-	1	1
						37
	The Geysers	Main Geysers	18	14	15	47
		Southeast Geysers	-	13	6	19
		Northwest Geysers	-	2	1	3
		North Geysers	-	1	2	3
		Howard Hot Springs	-	1	1	2
		Borax Lake	-	-	1	1
		Middletown	3	-	1	4
		Thurston Lake	-	1	-	1
		Castle Rock	4	-	-	4
		Cloverdale	1	-	-	1
		Mt. Konaocki	1	-	-	1
		Calistoga	3	-	-	3
						89
	Mono Co.	Long Valley	1	-	-	1
	Inyo Co.	Coso Hot Springs	1	1	-	2
	N.W. California	Lassen	-	-	1	1
						4
Nevada	Churchill Co.	Desert Peak	2	-	-	2
		Stillwater	3	-	-	3
	Lander Co.	Beowawe	1	-	-	1
	Carson Sink	Soda Lake	-	1	-	1
		Allen Springs	-	1	-	1
	Pershing Co.	Rye Patch	-	1	1	2
		Dixie Valley	-	-	1	1
		Gerlach	-	-	1	1
		San Emidio Desert	-	-	1	1
						13

Table II-2. (continued)

State	Region	Area	Number of wells 1976	1977	1978	Total
Oregon	Klamath Co.	Klamath Hills	1	-	-	1
		Mt. Hood	-	-	1	1
						2
Hawaii	Hawaii Island	Puna	-	-	2	2
						2
Idaho	Cassia Co.	Raft River	2	1	4	7
	Ada Co.	Boise	2	-	-	2
	Washington Co.	Crane Creek	-	1	-	1
	Owyhec Co.	Castle Creek	-	1	-	1
		Preston	-	-	1	1
						12
Utah	Beaver Co.	Roosevelt H.S.	3	1	1	5
		Thermo H.S.	-	-	1	2
	Millard Co.	Cove Ft.	1	1	2	4
	Iron Co.	Beryl Junction	2	-	-	2
		Lund	-	1	-	1
						14
New Mexico	Sandoval Co.	Fenton Hill	-	1	-	1
		Valles Caldera	-	-	1	1
						2
		TOTAL	65	51	58	175

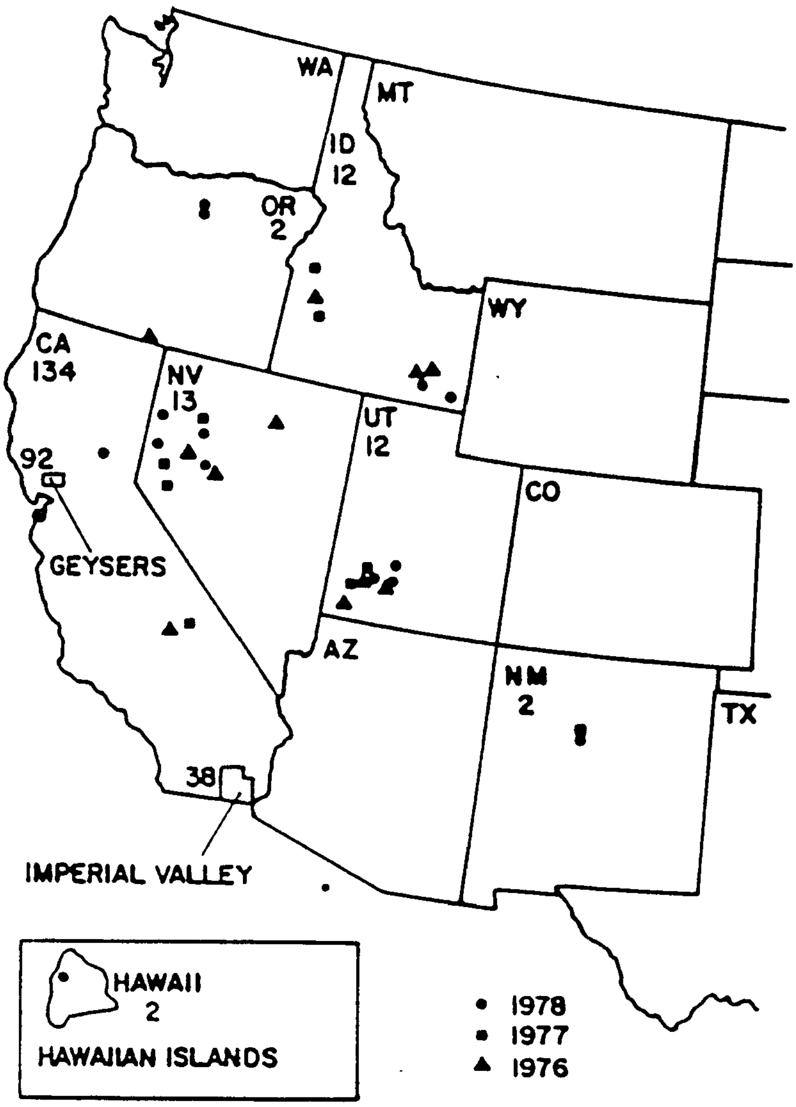

Figure II-7 Locations of Major Geothermal Drilling, Western USA, 1976-1973.

Source: Chilinger, G.V., L.M. Edward, W.H. Fertl, H.H. Ricke III, Editors, "The Handbook of Geothermal Energy." Houston, Texas, 1982, Gulf Publishing Company.

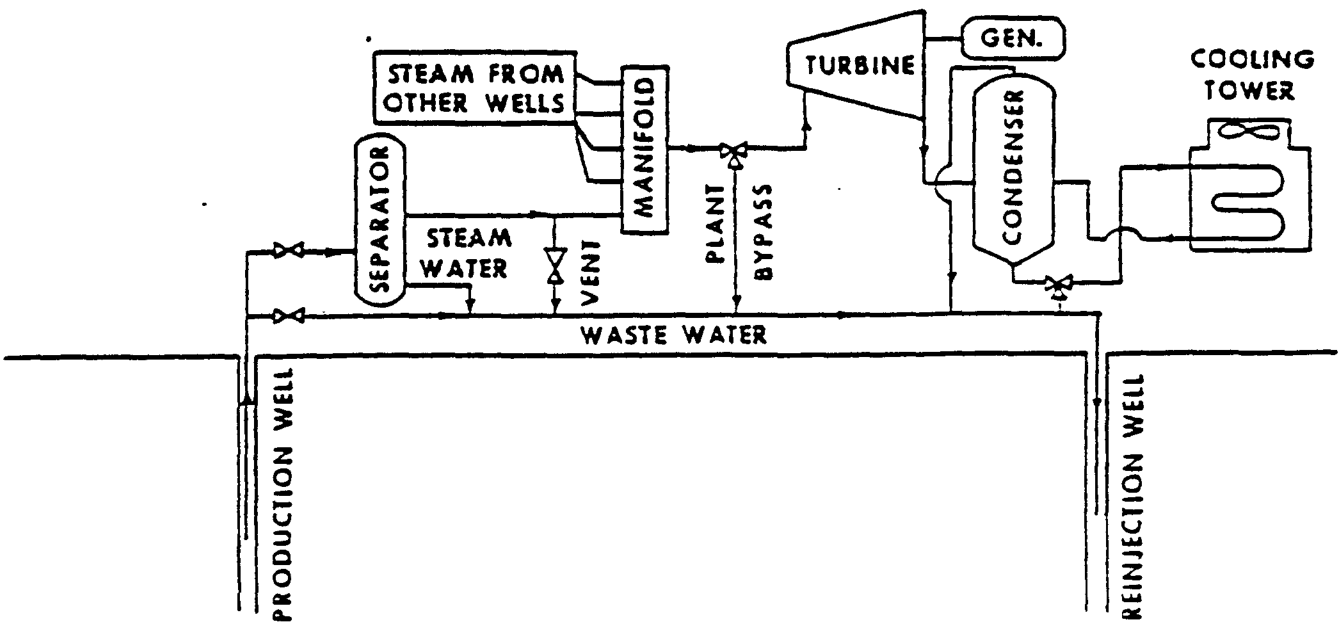

Figure II–8. Simplified Schmatic diagram of Conventional Steam Cycle Electrical Power Plant

Source: Hartley, R., "Pollution Control Guidance for Geothermal Energy Development," Industrial Environmental Research Laboratory, Office of Research and Development, U.S. EPA, 1978.

The binary cycle avoids the corrosion problem by employing a heat exchanger to transfer heat from the brine to a secondary working fluid. This fluid, usually isobutane or isopentane, is then used to drive a turbine. Binary cycles are much lower in thermal efficiency than flash injection systems. Figure II-9 presents a flow diagram for a binary system.

Current and Planned Development

Table II-3 presents a summary of the status (through 1985) and projected development of geothermal power plants in the U.S. These tables also describe power generating capacity as either operational, planned, or under construction; they also note process type.

The two best known power generating facilities, at The Geysers and at Imperial Valley, (both in California) utilize vapor-dominated resources. The Geysers (through 1985) had 1792 MW operational and plans to expand this capacity to 2660.2 MW. At Imperial Valley, the operational capacity is 32.5 MW and plans to increase capacity to 4140 MW. These two facilities together account for most of the installed capacity. However, other plants are being constructed, mostly in the western United States, to take advantage of the high temperature hydrothermal reservoirs which can be utilized economically (DiPippo, 1985).

DIRECT USE APPLICATIONS

In addition to the use of geothermal resources for the generation of electric power, the power plants may be used directly for heating,

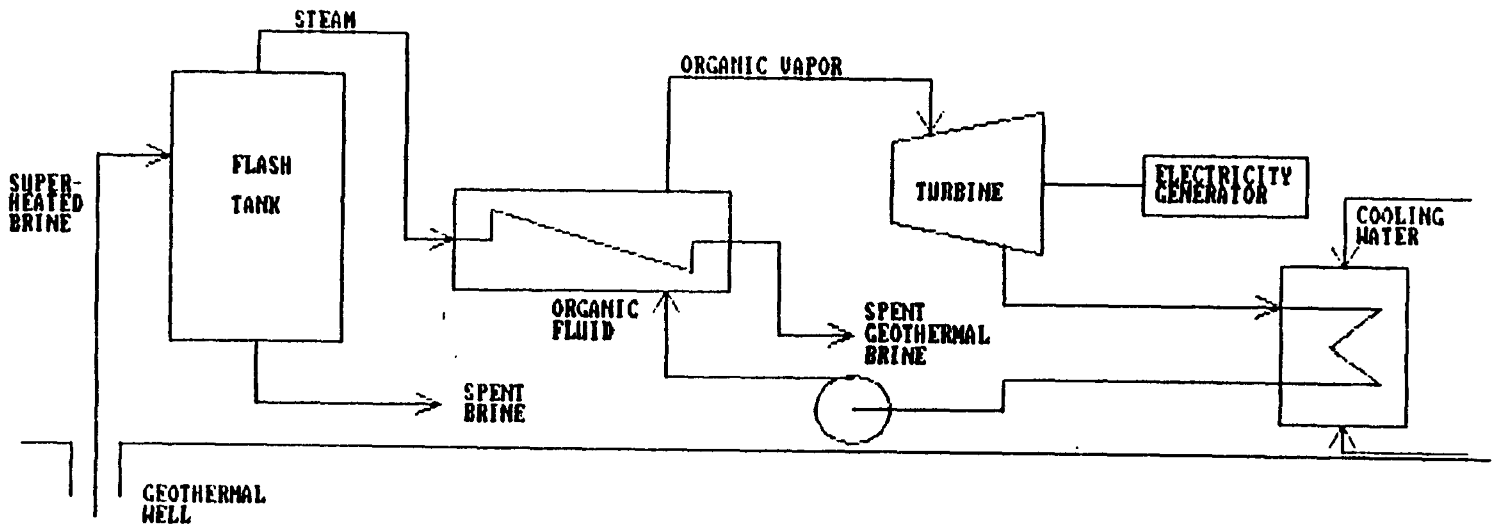

Figure II-9 Simplified Schematic Diagram for Binary Type Electric Power Generation System.

Table II-3. Geothermal Power Plants in the United States

Plant	Year	Type	MW	Status
California				
Cosco:	1986	1-Flash	25.0	Under construction
	n.a.	1-Flash	2 x 25.0	Advanced planning
Mammoth:	1984	Binary	2 x 3.5	Operational
	1985	Binary	5 x 0.6	Under construction
Honey Lake	1987	Hybrid: wood-geothermal	20.0	Under construction
Geysers:				
PG&E Geysers	1960-1985	Dry steam	1454	Operational
	1985	Dry steam	338	Under construction
	1988	Binary	141.2	Advanced planning
	n.a.	Dry steam	55	Advanced planning
	n.a.	Dry steam	617	Preliminary planning
	1988	Dry steam	55	Under CEC review
Imperial Valley				
East Mesa	1979	Binary	12.5	Operational
	1986	Binary	20.02	Under construction
	n.a.	Binary	50.0	Planned
Salton Sea	1982	1-Flash	1010	Operational
	1986	2-Flash	73.1	Under construction
	1985	2-Flash	31.4	Planned addition
	n.a.	2-Flash	49.0	Planned
Heber				
Binary Demo Plant	1985	Binary	45.0	Under construction
Flash Plant (HGC)	1985	2-Flash	49.0	Under construction
North Brawley	1980	1-Flash	10.0	Operational
Westmoreland	1988	Binary	15.0	Planned
So. Brawley (CU I)	n.a.	Flash	49.0	Planned
Hawaii				
Puna No. 1	1982	1-Flash	3.0	Operational

Table II-3. (continued)

Plant	Year	Type	MW	Status
Idaho				
Raft River	1982	Binary	5.0	Being moved to Brady H.S., NV
Nevada				
Wabuska Hot Springs	1984	Binary	0.6	Operational
Beoware	1985	2-Flash	17.0	Under construction
Brady Hot Springs	1986	Binary	8.3	Under construction
Steamboat Springs	1986	Binary	5.5	Planned
Fish Lake	1986	Binary	15.0	Planned
Big Smokey Valley	1986	Flash(?)	10.0	Planned
Desert Peak	1985	Total flow/ 2-Flash	9.0	Under construction
Spring Creek	1987	2-Flash	20.0	Planned
Dixie central	1987	Flash	20.0	Planned
Oregon				
Hammersly Canyon	1983-1984	Binary	2.01	Operational
Utah				
Milford:				
Blundell Unit 1	1984	1-Flash	20.0	Operational
Wellhead No. 1	1986	Total flow/ 2-Flasn	14.5	Under construction
Cove Ft Sulphurdale:				
Phase 1	1985	Binary	4 x 0.675	Operational
Phase 2	1985	Binary	2 x 1.0	Under construction
Phase 3	1986	Dry steam	2.3	Advanced Planning
		Totals:	1893.61	Operational*
			353.71	Operational or U.C.
			3331.11	Operational, u.c. or planned

* Includes plants under construction and scheduled for completion in 1985.

cooling, and a variety of other applications. Figure II-10 presents the potential extent of direct uses, as well as the approximate temperature range of use. In general, direct use of geothermal resources comprises applications in agriculture, aquaculture, space conditioning, and industrial processes. The end use distribution along with the use temperature is shown in Figure II-11. Space heating is by far the most widely practiced direct use application of geothermal energy, other uses include (Chilinger et al., 1982):

- Greenhousing;
- Mushroom culturing;
- Livestock raising;
- Soil warming;
- Aquaculturing (fish hatcheries, alligator breeding, etc.); and
- Biogas production.

Industrial uses may include applications such as:

- Preheating;
- Washing;
- Cooking and peeling (pulp and paper industry);
- Evaporating;
- Sterilizing;
- Distilling and separating;
- Drying; and
- Refrigeration.

There are two basic types of direct use systems: those that utilize the hydrothermal water itself and those that transfer the heat from the hydrothermal fluid to another fluid (a working fluid). The main reason for using a working fluid is to isolate the system from the hydrothermal

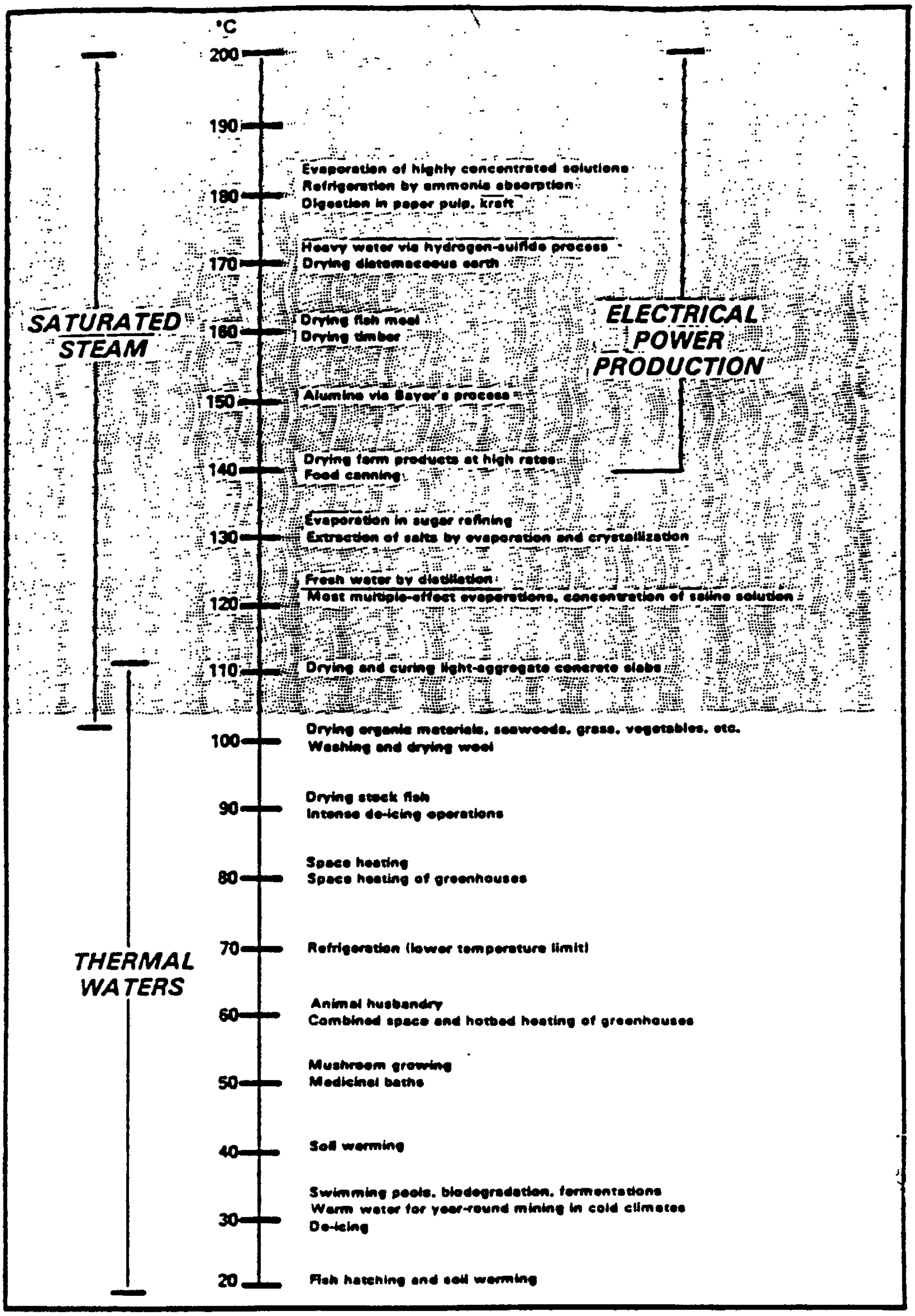

Figure II–10 Typical Geothermal Fluid Temperatures for Representative Direct-Use Applications.

Source: Chilinger, G.V., L.M. Edward, W.H. Fertl, H.H. Ricke III, Editors, "The Handbook of Geothermal Energy." Houston, Texas, 1982, Gulf Publishing Company.

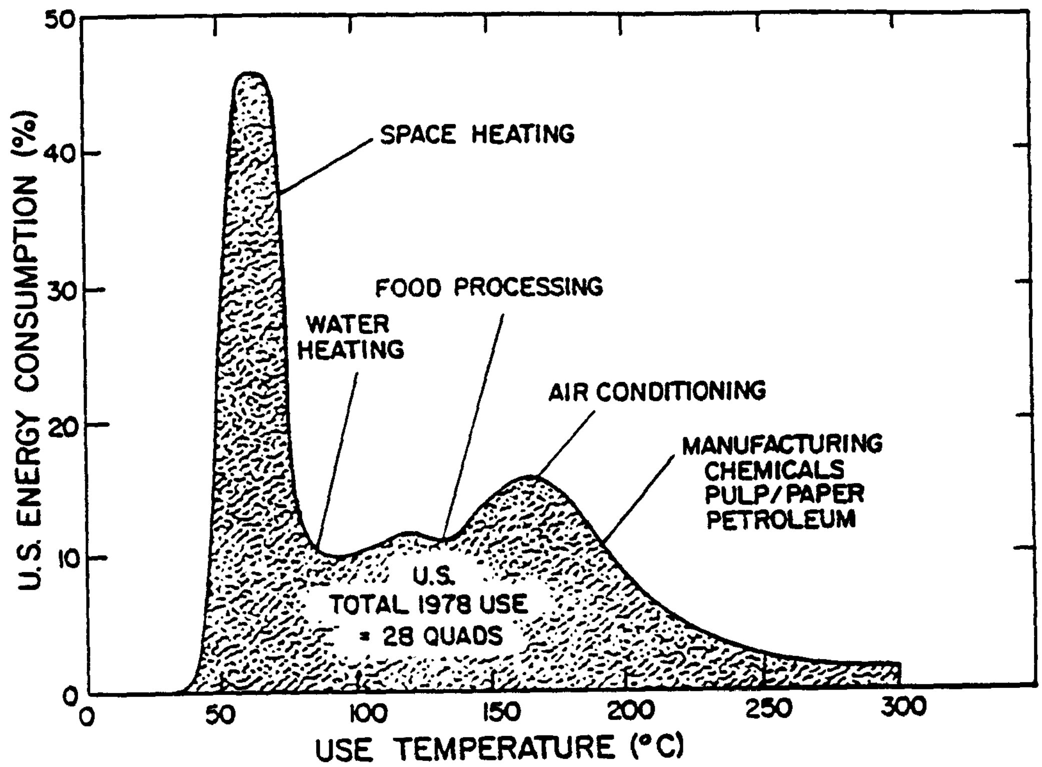

Figure II-11 Percentage Distribution of the Direct Use of Thermal Energy in the U.S. -- 1978.

Source: Chilinger, G.V., L.M. Edward, W.H. Fertl, H.H. Ricke III, Editors, "The Handbook of Geothermal Energy." Houston, Texas, 1982, Gulf Publishing Company.

fluid and its impurities and thus to confine or reduce corrosion and scaling problems. Such a system is shown in Figure II-12.

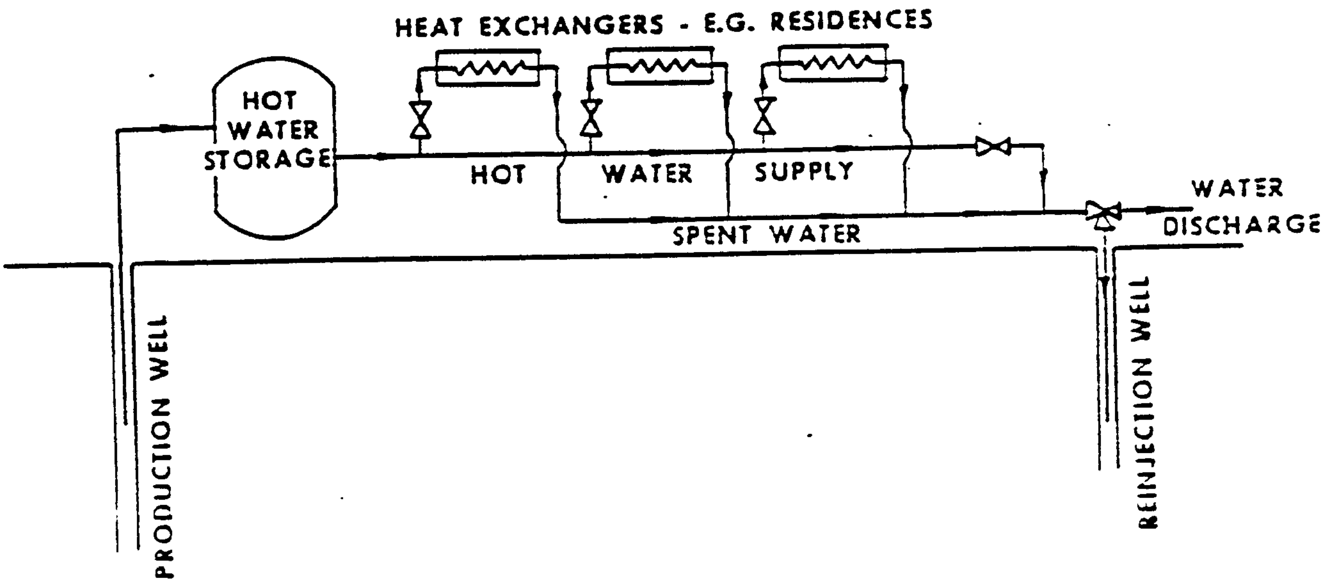

Figure II-12 Simplified Schematic Diagram of Non-electric Use (space heating) of Geothermal Energy. Spent Liquids Can Be Injected or Discharged to Surface Waters.

Source: Hartley, R., "Pollution Control Guidance for Geothermal Energy Development," Industrial Environmental Research Laboratory, Office of Research and Development, U.S. EPA, 1978.

CHAPTER 2

WASTE GENERATION

A review of available information indicates that there are two primary processes that generate wastes associated with the exploration, development, and production of geothermal energy. These wastes come from (1) the process of drilling and (2) the direct utilization of the resource. This section presents a brief description of how the wastes are generated and a suggested methodology for estimating waste volumes and characteristics. A substantial amount of information was derived from three previous studies (USDOE, 1982; USEPA, 1978; USEPA, 1983).

WASTE SOURCES

Drilling Wastes

The process of drilling for steam from a geothermal resource has been described in detail in the Industry Description. In a 1982 study (USDOE, 1982), it was estimated that (based on the experience of drilling 50 wells in the Imperial Valley in California) about 600 metric tons of mud and cuttings would be produced while drilling a typical 1,500-meter well.

Typically, there are four types of wastes generated by the drilling process. They are:

- Drilling fluid and drill cuttings;
- Deck drainings;
- Drilling fluid, cooling tower wastes; and
- Miscellaneous small waste streams.

Drilling Fluid Waste

A large quantity of drilling waste is derived from the drilling mud or the processing steps taken to reuse and recycle this material. The drilling fluids are "cleaned" by circulation through solids separation equipment, (i.e., shale shakers, sand traps, hydrocyclones, and centrifuges). After "cleaning," the drill cuttings and washwater are discharged and the "cleaned" muds are reused. There is, however, a point of diminishing return with the cleaning process. When the muds become too viscous, the muds must be discharged into a reserve pit. Muds also are discharged into the reserve pit when all drilling is completed or when entire mud systems are changed because of abrupt changes in drilling conditions.

Deck Drainings Wastes

Typically, drilling oprations generate deck drainings. These wastes are composed of rig washdown, rinses, drilling fluids, and other miscellaneous waste materials generated on or around the derrick. Depending on the type of drilling operations, these volumes can be substantial.

Drilling Fluid Cooling Tower Wastes

Some operations may necessitate the drilling fluids being cooled before it is recycled into the well bore. For those cases, the drilling fluid is circulated through a cooling tower. The tower will require occasional cleaning of scale and other deposits that build up in the tower.

Miscellaneous Small Waste Streams

Other wastes will also be produced in the drilling operations. These wastes consist of empty containers, bags, broken tools, paint wastes, minor spillages and leaks of diesel fuel, hydraulic fluid, wood pallets, and miscellaneous trash.

WASTE STREAMS FROM POWER PLANTS AND DIRECT USERS

It is convenient to classify the wastes generated from the usage of geothermal energy into two categories: (1) wastes derived from operations that use geothermal energy for electric power generation and (2) wastes derived from direct usage. These streams are discussed on the following pages.

Electric Power Generation

Presented below is a preliminary list of solid wastes that may result from the generation of power from geothermal energy. These wastes include:

- Reinjection well fluid wastes;
- Piping scale wastes, production well filter waste, and flash tank solids;
- Brine effluent precipitated solids; and
- Settling pond solids.

The sources of these wastes are shown schematically in Figures II-13 and Figure II-14 (USDOE, 1982).

Several other wastes are generated by electric power generation plants that utilize geothermal energy, but, as described in the Introduction, these wastes are not expected to be covered by the statutory exclusion or included in the final report. The wastes include the following:

- Makeup water treatment solids;
- Hydrogen sulfide removal wastes; and
- Cooling tower drift and blowdown.

These wastes are included in Figures II-13 and II-14 for completeness.

As indicated in Figure II-14, solid precipitates resulting from temperature and chemical changes in the brine during energy extraction constitute about one-half of the solid waste generated; well cuttings and drilling mud constitute about one-quarter; scale, solids from cooling water treatment, H_2S abatement, and other miscellaneous sources make up the balance. It is not known if these charts are typical of the industry in 1986. More data must be collected to verify these preliminary estimates.

Reinjection Well Fluid Wastes

The reject fluid from the geothermal power plant potentially can serve as a vehicle for disposal of most of the dissolved solid wastes when reinjected into an aquifer. However, brine injection can be complicated by precipitation of silica in high levels. The precipitation of silica has the tendency to occlude or cause co-precipitation of other dissolved ions present in the brine. Thus, the silica precipitate may contain heavy metals at elevated concentrations.

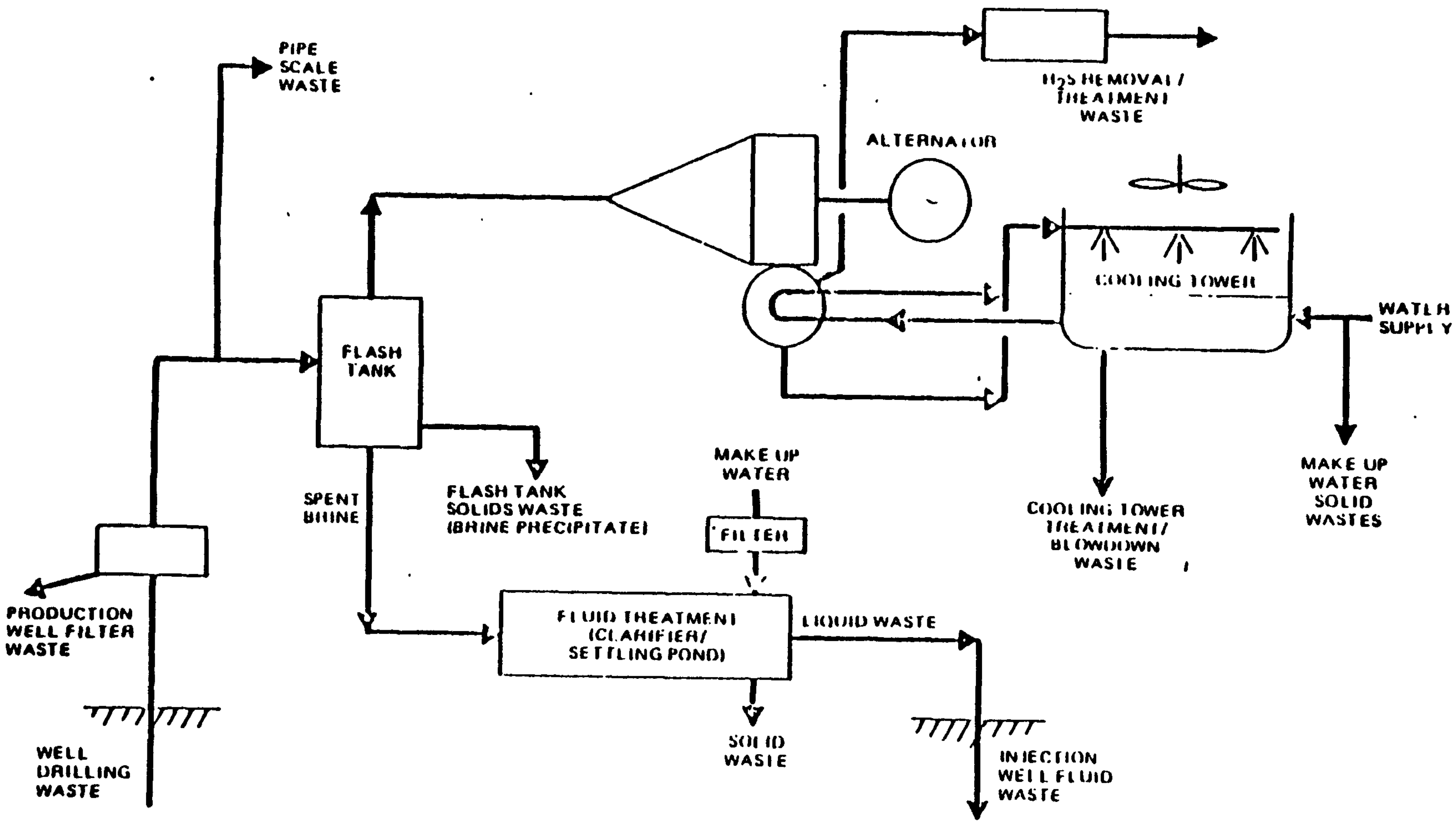

Figure II-13. Sources of Geothermal Solid Wastes.

Source: Darnell, A.J., et al., "Survey of Geothermal Solid Toxic Waste," Rockwell International Energy Technology Engineering Center, for U.S. Department of Energy, San Francisco, California.

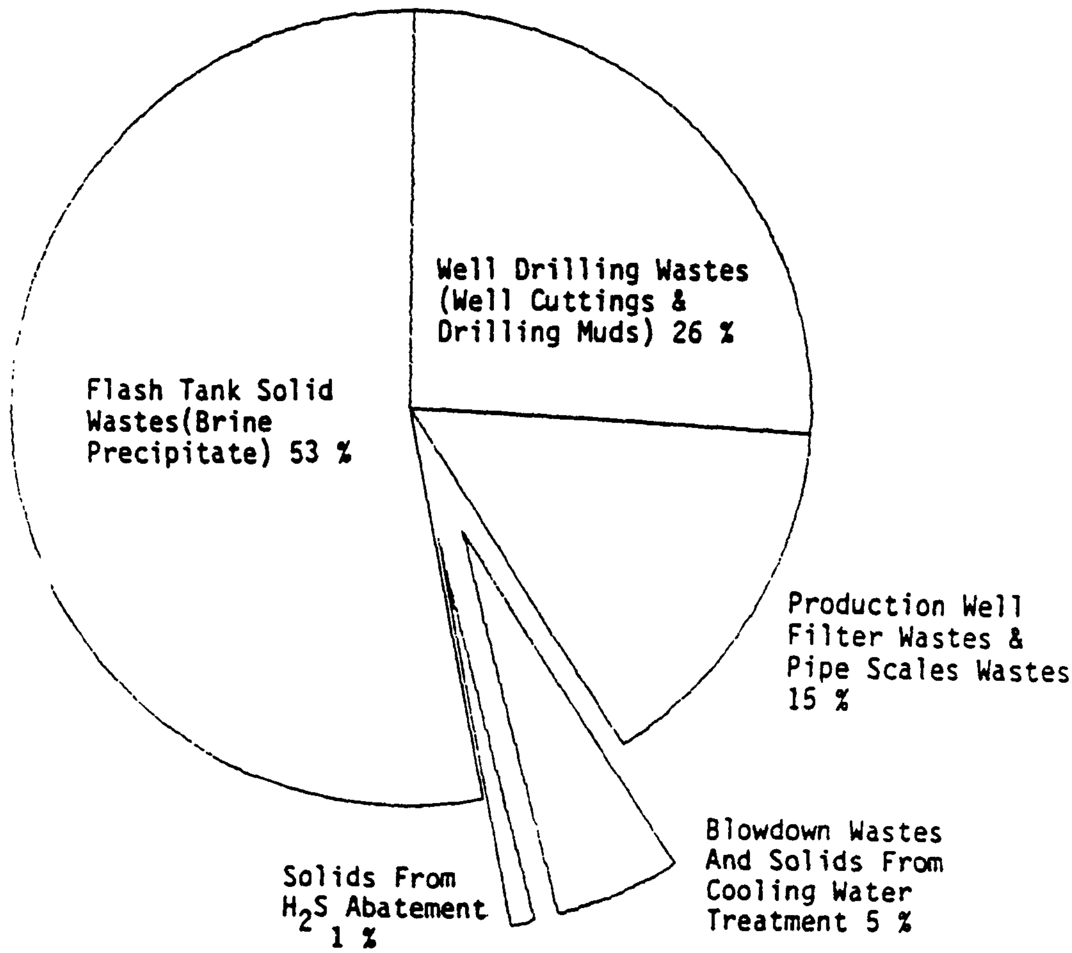

Figure II-14. Distribution of Solid Wastes from Development of a Liquid-Dominated Geothermal Resource.

Source: Darnell, A.J., et al., "Survey of Geothermal Solid Toxic Waste," Rockwell International Energy Technology Engineering Center, for U.S. Department of Energy, San Francisco, California, 1982.

Piping, Production Well Filter Waste, Scale Waste, and Flash Tank Solids

Scale can constitute approximately 15 percent of the solid wastes requiring disposal. Temperature, pH, chloride and sulfate ion concentration, and dissolved gases (CO_2, H_2S, NH_3) all influence the level of scale formation. Scaling and plugging may result from one or more of the following:

- Precipitation and polymerization of silica and silicates (silica in solution will neither precipitate nor adhere until it starts to polymerize);
- Precipitation of alkaline earths as insoluble carbonates, sulfates, and hydroxides;
- Precipitation of heavy metals as sulfides; and
- Precipitation of redox reaction products (e.g., iron compounds).

Silica precipitation and scale formation are among the major problems in geothermal energy conversion and injection systems.

Many of the factors causing the formation of scale from an aqueous solution could be reversible. It is, therefore, highly likely that scale would exhibit some solubility to surface waters under ambient conditions and that any toxic substances present in the scale would potentially be leachable.

Brine Effluent Precipitated Solids

Brine effluent precipitated solids generated from geothermal fluids are saline and may contain elements such as arsenic, lead, boron, and fluoride. If there is to be optimum utilization of heat, most brine effluents are returned to the reservoir. In some areas, such as the

Imperial Valley, these can be supersaturated with silica. Although amorphous silica may not deposit readily from water flowing in a pipe, separator, or heat exchanger, it is known to do so on concrete or brick surfaces. Thus, with time, it will reduce injectability by blocking the aquifer formation unless the chemical composition is carefully controlled. Therefore, treatment of the brines will have a major impact on the type and amount of solids that must be disposed of. In order to maintain its injectability in the accepting formation, it is necessary to adequately treat this brine effluent to rectify its supersaturated dissolved solids condition. Three processing methods used for treatment of geothermal brines are:

(1) Ponding of the brine effluent with reinjection of the clear liquor underground and landfilling any precipitated solids.

(2) Use of conventional water treatment technology to precipitate and remove solids and toxic materials. The wastewater would be injected and the solids hauled to a landfill.

(3) Processing the geothermal brine in such a way that minerals and useful byproducts are recovered from the brine. Solid wastes would then be disposed of in a landfill, and the clear liquid injected into the aquifer.

Settling Pond Solids

Settling pond solids are generated by spent brine holding ponds. A holding pond has been used at the East Mesa site for treatment of spent brine. This holding pond has sufficient residence time so that liquid withdrawn from the end opposite the injection point is sufficiently clear to be injected back into the aquifer. Solids that accumulate in the pond are dredged and then dried by evaporation and transported to a suitable landfill site. This method has been successful in those cases where the salinity of the brine is low. At the East Mesa site, the salinity of the brine is low compared to the Salton Sea sites. (USDOE, 1982)

Cooling Tower Drift and Blowdown

Cooling tower drift will be present whenever an evaporative type cooling tower is used. The drift is a fine mist of water droplets that escape from the top and sides of the tower during normal operation. Any compounds normally present in the cooling water will be carried out with the drift.

Direct Steam Usage

A brief discussion of direct resource utilization has been discussed in the Industry Description. Drilling wastes generated from these applications are expected to be similar to those produced for power generation. Information on waste sources from direct steam usage is currently being developed.

WASTE CHARACTERIZATION, COMPOSITION, AND VOLUMES

A preliminary review of information from selected data-bases indicates that the literature is limited in the areas of quantifying the sources, volumes, characteristics, and management techniques for specific wastes derived from some, but not the majority, of geothermal activities. Nevertheless, there is still enough data to provide the reader, in the interim, with a general sense of the types and characteristics of wastes that may be encountered as a result of the utilization of geothermal energy. We are currently reviewing the following:

- Chemical Abstracts;
- Enviroline;
- Pollution Abstracts;

- U.S. Geological Survey Library;
- U.S. Department of Energy, Geothermal Division Reports;
- Cambridge Scientific Abstracts;
- Sandia National Laboratories Technical Publications;
- Los Alamos Scientific Laboratory Publications; and
- Proceedings of the Geothermal Resources Council.

Because of data availability, this report will again draw heavily on the results of three EPA studies: published in 1978, 1982, and 1983, which were undertaken to characterize certain types of geothermal wastes at selected sites.

WASTE STREAMS FROM ELECTRIC POWER GENERATION AND DIRECT USERS

In 1983, major geothermal resource exploration and development sites in the western United States and the Gulf Coast were screened by Acurex under contract to EPA (USEPA, 1983) to locate candidate sites for sampling and analysis. A telephone survey of over 20 individuals representing 15 organizations was conducted to identify the types of solid wastes generated. These data appear to be the most detailed and comprehensive found to date.

As a result of the telephone discussion, follow-up letters, and several site visits, the sampling program was defined and permission obtained for collecting samples in three geothermal resource areas: the Imperial Valley -- 7 sites, The Geysers -- 11 sites, and Northwestern Nevada -- 3 sites.

The samples, collected on three field trips, encompassed the following:

	Total	Geysers, CA	Imperial Val., CA	Nevada
Drilling sumps				
Mud/fluid	8	2	3	3
Mud only	3			3
Fluid only	5		5	
Reinjection treatment				
Sediment ponds (brines)	3		3	
Flash tank	1		1	
Filter press	1		1	
Cooling tower basins	3	3		
H_2S removal				
Centrifuge (iron sulfide sludge dewatering)	3	3		
Stretford process sulfur recovery stream	1	1		
Miscellaneous				
Pipe scale	2		2	
Geological surface expression	1	1		
Landfill	2		2	

Of this sampling and analysis program was to evaluate the solid wastes for some RCRA hazardous waste characteristics and listing criteria proposed in 1978.

In addition to the eight constituents analyzed (Ag, Ba, Cd, Cr, Pb, Hg, Se, As), tests were also conducted for eight other metals in that study. These metals (Sb, Be, B, Cu, Li, Ni, Sr, Zn) were included because of their suspected presence in geothermal solid wastes and their listing in the water quality standards of several western States. Analytical results for these metals are summarized in Table II-4. In general, these levels were fairly low, except the levels for boron and zinc.

Table II-4. Summary of Results for Additional Metals

Metal	Range of Concentrations -- All Samples (mg/l)	Average Concentration All Values Above Detection Limit (mg/l)	Number of Values Above Detection Limit[b]
Antimony	0.05 - 0.18	0.14	3
Beryllium	0.020	--	0
Boron	0.2 - 660	43	26
Copper	0.05 - 60	9	12
Lithium	0.05 - 5.8	1.1	19
Nickel	0.2 - 0.90	0.50	11
Strontium	0.5 - 1,400	174	16
Zinc	0.020 - 6,000	203	30

[a]Includes results for both acid and ambient pH extracts.
[b]Total number of possible values (analyses) equals 42.

Additional organic analyses were conducted on three samples, presumably drilling wastes. Sample G12 was collected at the Class II-2 landfill in Brawley. This landfill contained a mixture of fresh solid wastes, predominantly drilling muds, from the Imperial Valley. Sample G24-1 was a geothermal drilling mud sample containing significant amounts of oil. Additives known to be present in this mud were bentonite, sodium hydroxide, calcium hydroxide, sodium tetraphosphate, and a polymeric material. Sample G22-1 was selected for organics analysis because cationic polyamines and anionic polyacrylamides are added to the iron sludge removed from the H_2S abatement centrifuge. These additives facilitate settling of the solids.

Three samples (two drilling muds and an iron sulfide) were screened for the 11 acid compounds and 46 base/neutral compounds listed as priority pollutants by EPA. Each sample gave two fractions for analysis by GC/MS. Phenol and phenol derivatives were found in all three samples. The occurrence of phenols in the drilling mud samples (G12 and G24-1) is probably due to the reaction of caustic soda (NaOH) with additives containing phenol groups. The alkaline nature of the muds and the final pH of the ambient extracts (both 9.4) suggest that the phenol is present as a sodium salt. This is confirmed by the higher concentration of phenol in the ambient extract (640 μg/l) compared to the acid extract (2 μg/l) in G24-1. Polynuclear aromatic compounds (PNAs) were also detected in G-12 and G22-1. For sample G-12, these could easily have come from asphalt (known to contain PNAs), which may have been used in an oil-based drilling mud system. The presence of a PNA in the iron sludge (G22-1) cannot be readily explained, since the only known additives were polyamines and polyacrylamides.

Tables II-5, II-6, and II-7 summarize the analytical results for these three samples. In addition to the trace levels of organics, the Brawley

Table II-5. Geothermal Analytical Data: Class II-2 Landfill

Number: G12 (1437) Type: Mixed Solids

Location: Brawley (Imperial Valley) Site Owner/Operator: Imperial County Dept. of Public Works

Bulk Composition	Total (%)	Acid Extract (mg/l)	Neutral Extract (mg/l)	Trace Elements	Acid Extract (μg/l)	Acid Extract (μg/l)
Aluminum (Al)	2.3	1	190	Arsenic (As)	100	250
Calcium (Ca)	1.60	680	33	Barium (Ba)	1,000	1,400
Iron (Fe)	1.2	0.8	76	Cadmium (Cd)	5	5
Magnesium (Mg)	1.72	20	52	Chromium (Cr)	23	420
Potassium (K)	0.69	48	85	Lead (Pb)	20	20
Sodium (Na)	0.50	235	230	Mercury (Hg)	1	Int
Chloride (Cl)	0.40	215	227	Selenium (Se)	20	50
Fluoride (F)	0.033	0.29	0.56	Silver (Ag)	20	20
Silica (SiO_2)	24.2	2	160	Antimony (Sb)	50	100
Sulfate (SO_4)	0.06	10	85	Beryllium (Be)	20	20
Sulfide (S)	0.01	0.1	0.1	Boron (B)	200	340
				Copper (Cu)	70	230
				Lithium (Li)	130	340
				Nickel (Ni)	200	200
				Strontium (Sr)	2,400	100
				Zinc (Zn)	250	1,400

ORGANICS

Priority Pollutants Detected		μg/l
Acid Extract	phenol	4
Neutral Extract	4,6-dinitro-o-cresol	18
	phenol	2
	Anthracene/phenathrene	6

OTHER PARAMETERS

Corrosivity	10 pH
Moisture	51%
TSS	NA
Radium 226	1.15 pCi/g

Table II-6. Geothermal Analytical Data: Iron Sludge from Centrifuge

Number: G22-1 (1579)　　Type: Sludge

Location: Unit 5 & 6 (The Geysers)　　Site Owner/Operator: PG & E

Bulk Composition	Total (%)	Acid Extract (mg/l)	Neutral Extract (mg/l)
Aluminum (Al)	0.01	1	1
Calcium (Ca)	0.005	2.4	2
Iron (Fe)	7.7	0.2	0.2
Magnesium (Mg)	0.005	0.20	0.16
Potassium (K)	0.004	0.18	0.15
Sodium (Na)	0.055	24	24
Chloride (Cl)	0.005	1	1
Fluoride (F)	0.001	0.12	0.14
Silica (SiO_2)	0.04	4	4
Sulfate (SO_4)	0.29	9.5	85
Sulfide (S)	0.2	0.1	0.1

Trace Elements	Acid Extract (µg/l)	Acid Extract (µg/l)
Arsenic (As)	20	20
Barium (Ba)	300	300
Cadmium (Cd)	5	5
Chromium (Cr)	20	20
Lead (Pb)	20	50
Mercury (Hg)	1	1
Selenium (Se)	20	20
Silver (Ag)	20	20
Antimony (Sb)	50	100
Beryllium (Be)	20	20
Boron (B)	28,000	27,000
Copper (Cu)	70	70
Lithium (Li)	50	100
Nickel (Ni)	200	200
Strontium (Sr)	500	500
Zinc (Zn)	60	30

ORGANICS

Priority Pollutants Detected		µg/l
Acid Extract	phenol	0.4
	Benzo (k) fluoranthene	14
Neutral Extract		None detected

OTHER PARAMETERS

Corrosivity	6.6 pH
Moisture	70%
TSS	NA
Radium 226	0 pCi/g

Table II-7. Geothermal Analytical Data: Abated Well Sump, Beigel #1 Well

Number: G24-1(1581R) Type: Mud

Location: Near Unit 18(The Geysers) Site Owner/Operator: Union Oil of California

Bulk Composition	Total (%)	Acid Extract (mg/l)	Neutral Extract (mg/l)
Aluminum (Al)	1.58	1	1
Calcium (Ca)	0.59	280	34
Iron (Fe)	3.03	32	0.2
Magnesium (Mg)	1.65	9.6	0.04
Potassium (K)	0.27	6.3	2.5
Sodium (Na)	0.11	24	48
Chloride (Cl)	0.014	2	1
Fluoride (F)	0.024	0.34	0.28
Silica (SiO_2)	19.4	4	16
Sulfate (SO_4)	0.02	32	62
Sulfide (S)	0.02	0.1	0.1

Trace Elements	Acid Extract (µg/l)	Acid Extract (µg/l)
Arsenic (As)	20	32
Barium (Ba)	300	300
Cadmium (Cd)	5	5
Chromium (Cr)	20	20
Lead (Pb)	20	20
Mercury (Hg)	1	1
Selenium (Se)	20	20
Silver (Ag)	20	20
Antimony (Sb)	50	50
Beryllium (Be)	20	20
Boron (B)	870	15,000
Copper (Cu)	70	70
Lithium (Li)	50	50
Nickel (Ni)	300	500
Strontium (Sr)	600	500
Zinc (Zn)	300	20

ORGANICS

Priority Pollutants Detected		µg/l
Acid Extract	2-nitrophenol	3
	phenol	2
Neutral Extract	phenol	640

OTHER PARAMETERS

Corrosivity	10 pH
Moisture	53%
TSS	NA
Radium 226	0.5 pCi/g

sites showed elevated levels of barium 1,400 $\mu g/l$ and the other two sites showed elevated levels of boron 1,500-27,000 $\mu g/l$ in the waste streams.

DRILLING WASTES

The 1982 EPA study (USDOE, 1982) provides a qualitative composition of a typical drilling fluid one might use in geothermal drilling operations. The report presents the results of sampled and analyzed drilling muds and cuttings at six power plant locations.

The report postulates that, while the well cuttings are not likely to be hazardous in themselves, they may be sufficiently contaminated with brine and drilling fluid to require special disposal. A summary of the results from the analysis of these samples is given in Table II-8.

Production Waste

Analyses were made of several other waste streams including:

- Piping scale wastes and flash tank solids;
- Settling pond solids and effluent;
- Cooling tower drift and blowdown; and
- Brine effluent precipitated solids.

Data from these was streams are included in the 1983 EPA study and are provided in order to establish the relative ranges of concentration present at one location. In general, all four effluents show low levels of arsenic. Barium results showed levels of barium (300 - 10,500 $\mu g/l$) in

Table II-8. Summary of Analysis from Drilling Muds

Location	pH	Radioactivity (pCi/g)	As	Ba	Cd	Cr	Pb	Hg	Se	Ag
			(Neutral Extract) (µg/L)							
East Mesa, CA	12.0	1.0	20	300	5	20	20	1	20	20
Niland, CA	8.4	2.1	20	300	5	20	20	1	20	20
Westmoreland, CA	8.8	5.9	41	6,800	5	20	20	1	120	20
The Geysers, CA (near Unit 13)	9.6	0.4	20	300	5	20	20	1	20	20
Steamboat, NV	9.3	1.0	260	300	5	20	20	1	20	20
Humboldt, NV	9.8	1.6	140	500	5	27	400	1	20	20
Desert Peak, NV	9.1	1.5	20	300	5	39	20	1	20	20

the acid extract and somewhat lower levels (300 - 5,400 $\mu g/l$) in the neutral extract. RCRA limits for barium are 100 $\mu g/l$. Arsenic levels range from 36 to 230 $\mu g/l$ in the acid extract and 33 to 230 $\mu g/l$ in the neutral extract. The analytical findings for lead ranged from less than 20 $\mu g/l$ to 200 $\mu g/l$ in acid extract and less than 20 $\mu g/l$ to 130 $\mu g/l$ in neutral extract.

DATA NEEDS

This waste information essentially represents "point" data, but is the best available at this time and shows characteristics that are believed to be highly site specific. Further data are required before definite conclusions can be reached about the nature and characteristics of waste generated from power production from geothermal resources.

Data are not available to allow the projection of total volume of mud and cuttings for the industry, and this must be developed. However, the 1982 EPA study estimated that 600 metric tons of cuttings and that mud would be generated by the drilling of one 1,500-meter well. These estimates are based on data derived from drilling 50 wells in the Salton Sea area of California.

In addition, information covering the volumes and composition of the waste from drilling operations must be developed. This information includes the volume and characteristics of mud pit solids, well cuttings, and cooling tower blowdown. Because of the dispersed nature of the industry, it is suspected that the results of these findings will show that the characteristics of these streams will be very site and geologic formation specific. If this is the case, then a comprehensive characterization of the industry will be very complex. Data are also required in order to prepare reliable estimates of volumes of wastes generated by the industry.

To fill these data gaps and to provide the data required to complete the study, the literature survey now underway will be completed. This manual literature search of waste characteristics and volumes will be supplemented by accessing the following data bases: Aqualine, Enviroline, Pollution Abstracts, and Chemical Abstracts. Appropriate articles will be obtained and the information combined with existing data. The information gathered from these data bases will be analyzed, tabulated, and summarized. Data gaps will be identified and geothermal facility owners/operators will be contacted to fill in these gaps. RCRA 3007 questionnaires and field sampling may also be required, if appropriate. The Petroleum Equipment Supplier's Association has also agreed to provide data to assist in the calculation of waste volumes.

The outputs from the review will be (1) an up-to-date listing of active and planned geothermal power and direct stream users; (2) an analysis of the amount and quality of waste characterization, treatment, and disposal information available for each facility or geothermal region; and (3) a firm estimate of additional data required.

Following EPA review and approval of area selection, drillers, owners, and operators in each area will be contacted either by letter or telephone to request their voluntary cooperation with this program. The goal is to find a few operators in each area who would be willing to provide process details, waste characterization and allow site sampling, if necessary.

Once industry contact has been established, data from each site will be collected and an assessment will be made as to the necessity of site visits and waste sampling. If laboratory work is required, a sampling and analysis plan will be prepared and arrangements will be made for the actual sampling and analytical work to be conducted. Use will be made of similar existing sampling and analysis plans, where appropriate, to expedite the work.

Engineering studies will then be conducted, where necessary, to define and evaluate alternative disposal methods, and to review and analyze the results of the field studies. Concurrent with the field survey activities, a preliminary list of alternative waste disposal options will be prepared. The sources of these options will be the literature and engineering judgment.

CHAPTER 3

WASTE MANAGEMENT

Although the treatment and disposal methods for wastes from geothermal operations are not well documented in the published literature, there is some consistency in the reported methods. For example, the literature reports that most geothermal wastewaters are reinjected into the geothermal field (USDOE, 1982; USEPA, 1978). At the Geysers reinjection into the same formation was started in 1969. Billions of gallons of geothermal brine effluents have been reinjected since then. Cooled geothermal effluent when reinjected back into the same formation, scavenges heat from the reservoir rock matrix and may be withdrawn again. Steam condensate that is reinjected may be withdrawn again as steam. This reinjection process provides for a higher recovery rate of the stored heat, helps prevent subsidence, and helps maintain the reservoir pressure. Air emissions are not addressed in this report, but will be discussed in the draft Report to Congress.

Old production wells may be converted to use as injection wells or new wells may be drilled. Injection can be accomplished by gravity alone because of the higher gravity head of the cooler and denser wastewater, but pumps are usually provided. The efficiency of the injection operation is highly dependent on the physical, chemical, and thermodynamic characteristics and interrelationships of the wastewater, as well as the reservoir fluids and rocks.

Pretreatment may be required before injection to prevent silica plugging, scaling, and pipe corrosion. Generally, the pretreatment involves settling, coagulation, clarification and filtration. The addition of corrosion or scale inhibitors may also be required.

Most of the available treatment and disposal data are old and will be updated. A data search is being undertaken to identify waste characteristics that will provide data on treatment/disposal processes. This information will be combined with the existing data and data gaps will be identified.

Where data gaps exist, current information will be solicited first by telephone and then, if necessary RCRA 3007 questionnaires will be sent to selected operations. If field sampling of wastes is required, then data will also be requested on both current treatment/ disposal practices and alternative treatment/disposal processes.

Some information is available on alternative treatment/disposal processes. Many of these alternative processes have been field tested. Existing data on the effectiveness of these processes will be evaluated and compared to engineering studies to establish viable alternatives.

CHAPTER 4

COST OF CURRENT AND ALTERNATIVE DISPOSAL PRACTICES

The literature contains some outdated cost estimates for treatment processes that were in use during the late 1970s. Much of these data can be inflated with appropriate indices in order to obtain current cost estimates for those particular treatment/disposal processes represented. The Agency is in the process of reviewing additional literature that has been collected to locate more recent estimates for these current processes. In addition to these published sources of data, a small sample survey will be conducted to obtain up-to-date data on current treatment and disposal practices. This survey will seek cost data (both investment and operations/maintenance) on these processes. These collection cost data will provide the basis for estimates of current waste practice cost.

In order to compare various alternatives, a cost estimate will be derived for each individual process or practice. It is important to know the cost of both current and alternative treatment processes so that the incremental cost of any new treatment processes can be evaluated when economic impacts are calculated.

DEVELOPMENT OF ESTIMATES

There are several methods for preparing cost estimates. Selection of a method to be used depends on the amount of detailed information available and the accuracy desired. The following list briefly describes the primary cost estimating techniques, any of which could be the most appropriate, depending upon design constraints and guidelines of a specific project.

Bottom-up Technique

The bottom-up approach to estimating, also called the detailed take-off technique, requires a detailed definition of all the equipment and material needs for a given project. This explicit itemization is accomplished through the use of completed drawings, flow sheets, and specifications. Equipment cost data are generally obtained from firm equipment bids based on detailed purchase specifications. Costs for engineering, supervision, installation, etc., are determined using accurate labor rates, employee-hours standards, and productivity assumptions. These costs are accumulated from the "bottom up" to obtain a total cost estimate. Accuracy is usually ±10 percent.

Parametric Technique

Parametric estimating requires historical data bases on similar systems or subsystems. For example, costs may be estimated for a proposed facility by finding correlations among projects completed in the past that use similar design or performance parameters (known as cost drivers) in addition to using the same or similar equipment items. The analysis produces cost equations or cost estimating relationships that can be used individually or grouped into more complex models. Accuracy is usually within an order of magnitude for estimates of this types.

Specific Analogy Technique

Specific analogies use the known cost of a prior system as the basis for estimating the cost of a similar new system. Adjustments are made to known costs to account for differences in relative complexities of performance, design, and operational characteristics. Accuracy is usually ±30 percent.

Cost Review and Update Technique

The cost review and update estimate is constructed by examining previous estimates of the same or similar projects for internal logic, completeness of scope, assumptions, and estimating technology. The estimates are then updated to reflect the cost impact of new conditions or estimating approaches. Sometimes a contractor efficiency index is derived by comparing originally projected contract costs to actual costs on work performed to date. The index is used to adjust the cost estimate of work not yet completed. Accuracy is usually ±5 percent.

Factored Cost Technique

Factored cost estimating incorporates elements of several estimating techniques including portions of those previously discussed. The first step in factored cost estimating is to develop an equipment list from process flow diagrams or engineering drawings. Costs for major equipment items are collected from various data sources such as vendor quotes, equipment catalogues, and recent prices for the same or similar items. The total equipment cost is then used in determining the add-on costs of installation/erection, piping, instrumentation, insulation, electrical system, and engineering. These add-on costs are calculated as a percentage (based on extensive historic experience) of the total equipment costs and vary depending on the process involved, difficulty of installation, design complexity, past experience, etc. This results in a total direct plant cost to which indirect costs such as the contractor's fee and contingency costs are added. Fee and contingency costs are usually estimated as the percentage of the total direct plant cost.

It is anticipated that all but the bottom-up technique may be used to derive estimates for alternative geothermal treatment processes. It is not believed that detailed drawings will be available in order to permit use of this more costly and time-consuming estimating approach. It is likely that many of the estimates will be updates of previous estimates or analogies. Some parametric estimating relationships exist in the published data, and these are also likely to be used for certain processes.

Each estimate will be normalized to account for inflation, geographic location, geothermal production rate, and similar factors that might tend to skew a comparison between existing and alternative practices. Similar cost estimate categories will be used so that the same adjustments can be made to financial statements in order to determine total economic impacts. At a minimum, costs will be broken into capitalized investment costs and annual operations maintenance costs.

CHAPTER 5

ECONOMIC IMPACTS OF ALTERNATIVE METHODS OF TREATMENT AND DISPOSAL

An economic impact assessment analysis will be conducted in future work on a facility-by-facility basis. This assessment will encompass evaluation of impacts on production costs, profitability, and liquidity. In addition, an analysis of the impact on plant profitability and the likelihood of plant closure will be made using computerized discounted cash flow techniques. As a last step, small business and community impacts will be calculated. In order to account for uncertainty, sensitivity studies will be conducted wherein major variables and assumptions will be varied to assess the impact.

The economic impact analysis will begin with a definition and description of the industry. This industry description will include geographic locations, production levels, income, prices/rates, product volumes, employment levels, production costs, and profitability figures. Product differentiation, substitution, demand elasticity, and barriers to entry also will be evaluated. Much of the data necessary for the industry description is currently available, but needs validation and updating. Since several of the facilities will be experimental, the data reported may vary from facility to facility. This descriptive material will establish a baseline case for each facility.

An economic impact assessment consists of a comparison of current financial measures, in which the cost of current waste treatment processes is reflected, with pro forma financial measures in which selected alternative waste treatment options are substituted. The financial measures will include production costs, profitability, and liquidity. Ideally, these financial comparisons will be conducted at the facility level so that the economic impact on the geothermal facility can be isolated and quantified. Financial data will be obtained from State Public Utility Commissions (PUCs). Regulated utilities are required to file periodic statements with the PUCs, which contain information regarding production costs, taxes, profits, assets, and other financial data. These data will be gathered for each geothermal electric generation production facility and for each regulated heating district. The PUC data will form the baseline case that reflects current disposal practices.

The cost of disposal practices evolving from the cost analysis will provide both capital investment and operations/maintenance costs for both existing and alternative waste treatment/disposal systems. The impacts of the existing treatment/disposal systems will be subtracted from the baseline financial data, and the cost of removing the old system and installing and operating the new system will be added. The impact of this change will be reflected in a mills/kwh or similar measure that can be compared to the estimated cost of alternative energy. The impact on profitability as the final step of determining the economic impacts, a closure analysis will be conducted wherein the current liquidation value of the facility is compared to the present values of cash flow over the remaining life of the facility. From this closure analysis, the impact on employment, small business, and the community can be estimated.

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Part III

Damage Case Assessment

CHAPTER 1

INTRODUCTION

Section 8002(m) of the Solid Waste Disposal Act, as amended in 1980, requires EPA to conduct a detailed and comprehensive study of the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with exploration, development, or production of crude oil, natural gas, or geothermal energy. As specified in the Act, adverse effects may include, but are not limited to, effects of wastes on humans, water, air, health, welfare, and natural resources. The study must also review the adequacy of means and measures currently employed by the oil, gas, and geothermal drilling and production industries to prevent or substantially mitigate such adverse effects.

The most direct method for meeting this requirement for estimating possible damages is through the use of documented damage cases; Congress has therefore directed EPA, under Section 8002(m)(D) of RCRA, to develop such damage case data. A second method proposed by EPA for estimating damage is through the use of risk assessment (described in Part IV of this report). The two approaches are independent, but are intended to complement and corroborate each other. Data developed under the damage case review for this project will not be used as input to risk assessment models or methods.

This part of the report deals with EPA's proposed methodology for gathering damage case data in a comprehensive, structured, and fully documented manner. The methods described below to gather, document, and interpret damage case data are simple and straightforward. EPA's overall goal is to develop a compendium of available information on the incidence of environmental contamination or damage, both actual or suspected, that may be caused by the disposal of wastes from the subject industries.[1]

Although it is impossible to determine precisely what types of adverse impacts are caused by oil, gas, and geothermal operations before completing the damage case review, the general categories of damage expected are as follows:

- Human health effects (acute and chronic). While there may be instances where contamination has resulted in documented cases of acute adverse human health effects, such cases are expected to be rare. Levels of pollution exposure caused by oil, gas, and geothermal operations are more likely to be in ranges associated with chronic carcinogenic and non-carcinogenic effects. The damage case study will therefore seek to document instances where operations result in levels of exposure associated with potential long-term chronic effects, rather than attempt to document the adverse effects themselves.

- Environmental effects. This type of damage would include impairment of natural ecosystems and habitats, including contamination of soils, impairment of terrestrial or aquatic vegetation, or reduction of the quality of surface waters.

- Effects on wildlife. This would include impairment to terrestrial or aquatic fauna; types of damage could include reduction in species' presence or density, impairment of species health or reproductive ability, or significant changes in ecological relationships.

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1 If necessary, the approaches described below may be modified or expanded over the course of the project in order to support this goal or in response to comments received on this initial report.

- Effects on livestock. Damage in this category would include morbidity or mortality of livestock, impairment in the marketability of livestock, or any other adverse economic impacts on livestock.

- Impairment of other natural resources. This category could include contamination of any current or potential source of drinking water, disruption or lasting impairment to agricultural lands or commercial crops, impairment of potential or actual industrial use of land, or reduction in current or potential use of land.

CHAPTER 2

APPROACH FOR COLLECTING DAMAGE CASES

The proposed approach for collecting damage case data involves four separate activities: (1) specification of information types required, (2) identification of case study information sources, (3) specification of procedures for collecting data, and (4) specification of criteria for classifying cases. Each activity is discussed separately below.

SPECIFICATION OF INFORMATION TYPES REQUIRED

The initial phase of the damage case study will identify the types of information necessary for fulfilling the directive of Section 8002(m)(D). The types of information EPA plans to gather will also support the Agency's assessment of potential danger to human health and the environment from surface runoff or leachate required in Section 8002(m)(C).

The information to be collected for each incident includes:

- Characterization of specific damage types. This will involve identification of the environmental medium or media involved, the type of incident, and a characterization of actual or suspected damage.

- The size and location of the site. Each site's location will be noted, especially for its hydrogeological and other pertinent environmental factors.

- The operating status of the facility or site. A notation of whether the site is active or inactive will be made.

- Identification of the type and volume of wastes. For each incident, EPA will characterize the types and volumes of oil, gas, or geothermal wastes involved. This will include identification of constituents and constituent concentrations in the wastes associated with the contamination or damage.

- Identification of waste management practices. For each incident, information is required on the types of waste management practices causing or contributing to the contamination or damage.

- Identification of any pertinent regulations affecting the site. These could include local, State, or Federal rules governing environmental releases, health and safety requirements, production restrictions, or any other relevant factors.

- Type of documentation available. For each case, the nature of the available documentation must be noted. This may include environmental monitoring data, site inspection reports, records of citizen complaints, litigation, enforcement-related information for a local, State, or Federal rule violation, court records, or records of administrative decisions.

IDENTIFICATION OF CASE STUDY INFORMATION SOURCES

The next phase of this effort will be to identify a full range of potential sources of damage case information.

Although oil, gas, and geothermal operations exist in 33 States, 98 percent of the 1985 drilling activity and 97 percent of all producing wells in the United States lie within 21 of those States. Because of time and resource limitations, EPA will restrict its damage case study to these 21 States (see Table III-1). Furthermore, no attempt will be made to conduct a complete census of all known damage cases, current or

Table III-1. List of States from Which Case Information Is Being Assembled

1. Alabama
2. Alaska
3. Arkansas
4. California
5. Colorado
6. Illinois
7. Kansas
8. Kentucky
9. Louisiana
10. Michigan
11. Mississippi
12. Montana
13. New Mexico
14. North Dakota
15. Ohio
16. Oklahoma
17. Pennsylvania
18. Texas
19. Utah
20. West Virginia
21. Wyoming

historical, within these States. Rather, EPA will seek to construct a representative sample of cases based on criteria presented in the next subsection (see below).

Sources of information relating to the selected States will include, but are not necessarily limited to:

- Relevant State or local agencies. These will include State environmental agencies, oil and gas regulatory agencies, State, Regional, or local departments of health, and other agencies potentially knowledgeable about damage cases.

- EPA Regional Offices.

- U.S. Bureau of Land Management.

- U.S. Forest Service.

- U.S. Geological Survey.

- Professional or trade organizations.

- Public interest or citizens' groups.

An attempt will be made to contact as many potential sources of information as is possible in each of the 21 States to be surveyed. All information collected, from whatever source (Federal, State, or local), will be furnished to appropriate State agencies for review prior to incorporation in this study.

SPECIFICATION OF PROCEDURES FOR COLLECTING DATA

The third phase of the study will be to select an appropriate sample of cases from the range of those uncovered by contacts with the organizations listed above. Documentation will then be gathered on this sample.

Criteria have been established for guiding detailed data collection efforts. Cases selected for investigation will emphasize:

1. Recent cases. Cases that have occurred recently are the most likely to reflect current waste management practices.

2. Cases that illustrate clear relationships among environmental damage and specific waste management practices. Such links may best be documented where scientific investigations have been conducted at the involved sites.

3. Cases where the most significant levels of damage have occurred. The Agency will seek to document as wide a range of damage types as possible (see above).

Once sample cases have been selected for investigation, the Agency will attempt to develop as much documentation as possible for each case. This will include:

- Site investigation reports performed by State agencies in response to citizen complaints;
- Inspection reports of unsatisfactory waste management;
- Follow-up site investigations, memoranda, and reports on individual sites;
- Special studies performed on local or Regional issues that describe specific sites' problems;
- Testimony of expert witnesses in administrative or court proceedings; and
- Compliance orders or other administrative directives, with supporting documentation, issued by State enforcement offices.

EPA believes that these materials will contain the information required to satisfy Congress's directives, but will also review any other available, appropriate information.

<u>SPECIFICATION OF CRITERIA FOR CLASSIFYING CASES</u>

The final step of the damage case review project will be to classify the collected damage cases and subject them to a test of proof. For the purpose of this study, EPA will consider that a case has met the test of proof if the damage, as defined above, is documented and is determined to have been caused by oil, gas, or geothermal operations (1) through the conclusion of a scientific investigation of the case, (2) by an administrative ruling, or (3) by court decision.

Cases that fail to meet the test of proof will not be discarded, but will be retained to furnish additional background information relevant to other needs of this study.

CHAPTER 3

APPLICATION OF DAMAGE CASE RESULTS

EPA intends to use the information contained in the damage cases to support the assessment of the potential danger to human health and the environment. EPA plans to present descriptive information from these cases illustrating empirical relationships among damage types and particular types of wastes, particular environmental contexts, and particular waste management processes.

In addition, summary data will be cross-referenced by:

- Damage type. (As discussed above).
- Waste type. This will include consideration of the physical, chemical, and toxicological characteristics of wastes.
- Environmental setting. Information will be referenced, as appropriate, by hydrogeological characteristics, aquatic features, meteorology and climatic regime (e.g., proximity of site to surface water, net infiltration, surface and ground-water quality and flow velocity), and any other relevant environmental factors.
- Exposure. Information will be referenced, as appropriate, to important human or ecological exposure pathways (e.g., proximity to public or private drinking water wells or surface water intakes, exposure to agricultural crops or through food animals, etc.).

The Agency wishes to emphasize that these data on damage estimation will be compiled independently to the risk assessment. None of the data gathered by this effort will be directly used in the modeling analysis (see Part IV, following). The basic goal of this effort is to compile empirical descriptive data on the existence of damages associated with exploration, development, and production, to characterize as representatively as possible the nature and extent of these damages, and to link causes and effects to the extent feasible.

Part IV

Risk Assessment

CHAPTER 1

INTRODUCTION

Section 8002(m) of the Solid Waste Disposal Act, as amended in 1980, requires EPA to conduct a detailed and comprehensive study of drilling fluids, produced waters, and other wastes associated with exploration, development, or production of crude oil, natural gas, or geothermal energy. Section 8002(m)(1)(C) directs EPA to analyze the potential danger to human health and the environment from surface runoff or leachate resulting from these activities. This part describes the proposed approach for a risk analysis to fulfill the requirements of Section 8002(m)(1)(C). The approach is applicable to both oil and gas operations and geothermal energy operations, although the input data for the analysis will differ for the two industry categories.

The objectives of the risk analysis are to (1) characterize and classify the major risk influencing factors (e.g., waste types, disposal technologies, environmental settings) associated with current waste management practices at oil and gas and geothermal energy facilities;[1]

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[1] In this part all references to oil and gas and geothermal energy facilities or sites refer to exploration, development, and production operations.

(2) estimate distributions of risk influencing factors across the population of facilities; (3) rank these factors in terms of their relative risks; and (4) develop initial quantitative estimates of the range of baseline health and environmental risks for the variety of waste types, management practices, and environmental settings that exist.

To meet these objectives, the risk analysis will estimate health and environmental risks from fully specified model scenarios that represent the range of wastes, release sources, and environmental settings typical of onshore oi; and gas and geothermal energy operations. The Agency will develop the model scenarios based on its review and analysis of available data on actual oil, gas, and geothermal energy facilities, including the information obtained from its sampling efforts (see Part I). This analysis will not estimate site-specific risks nor will it produce a rigorous quantitative estimate of national population risks. It will, however, produce methods, modeling techniques, and a partial data base that could be adapted for that purpose. The proposed risk analysis also will produce initial estimates of health risks and potential environmental damages, identification of low-risk and high-risk scenarios, and rankings of major risk influencing factors consistent with the purpose of the Section 8002(m) requirements. This risk assessment will address only current conditions in the industry; it will not analyze regulatory alternatives to reduce the baseline risk.

As with any National assessment of risk from waste generating activities, whether based on specific real facilities or model facility scenarios, many assumptions will be necessary for this analysis. Assumptions are necessary for at least three reasons: (1) lack of important data about waste generating and management practices and environmental conditions, coupled with the expense of obtaining such data; (2) significant limitations of available methods for modeling chemical release, transport, fate, and effects; and (3) modeling feasibility and practicality, which are essential considerations to any National risk analysis with a broad scope. Any assumptions in the analysis will be explicit, and EPA will document them carefully in written reports.

The remaining chapters in this part describe the proposed risk assessment methodology. The next chapter gives an overview of the approach to provide the reader with an overall perspective. Following that, the input data to be used in the analysis are discussed in Chapter 3, and Chapter 4 describes EPA's planned approach to characterizing oil and gas and geothermal energy facilities. The development of combinations of release source types, waste types, and environmental settings (i.e., model scenarios) is discussed in Chapter 5. The modeling techniques to be used in the risk estimation calculations are described in Chapter 6, along with the areas needing further model development and refinement. Finally, Chapter 7 summarizes the actual risk calculation, which will follow finalization of the model scenarios and modeling tools.

CHAPTER 2

OVERVIEW OF THE RISK ASSESSMENT APPROACH

Potential health and environmental risks associated with waste management activities depend on the types and quantities of wastes being managed; the storage, treatment, and disposal technologies being used; and the environmental settings in which the waste management activities are carried out. These factors determine the degree to which receptors (human or environmental) may be exposed to harmful constituents of the waste through various exposure pathways. Risk is estimated by combining exposure information with data on the toxicity of specific chemicals and information on the characteristics of receptor populations.

The following section summarizes the specific risk assessment methodology to be used in the oil and gas and geothermal energy study. Following this overview, there is a brief description of alternative risk assessment methodologies that were considered for the study and rejected.

OVERVIEW OF THE RISK ASSESSMENT METHODOLOGY

EPA proposes to conduct a generic, as opposed to site-specific, risk assessment of onshore oil and gas and geothermal energy operations. A schematic overview of the approach is given in Figure IV-1. A key part of

Figure IV-1

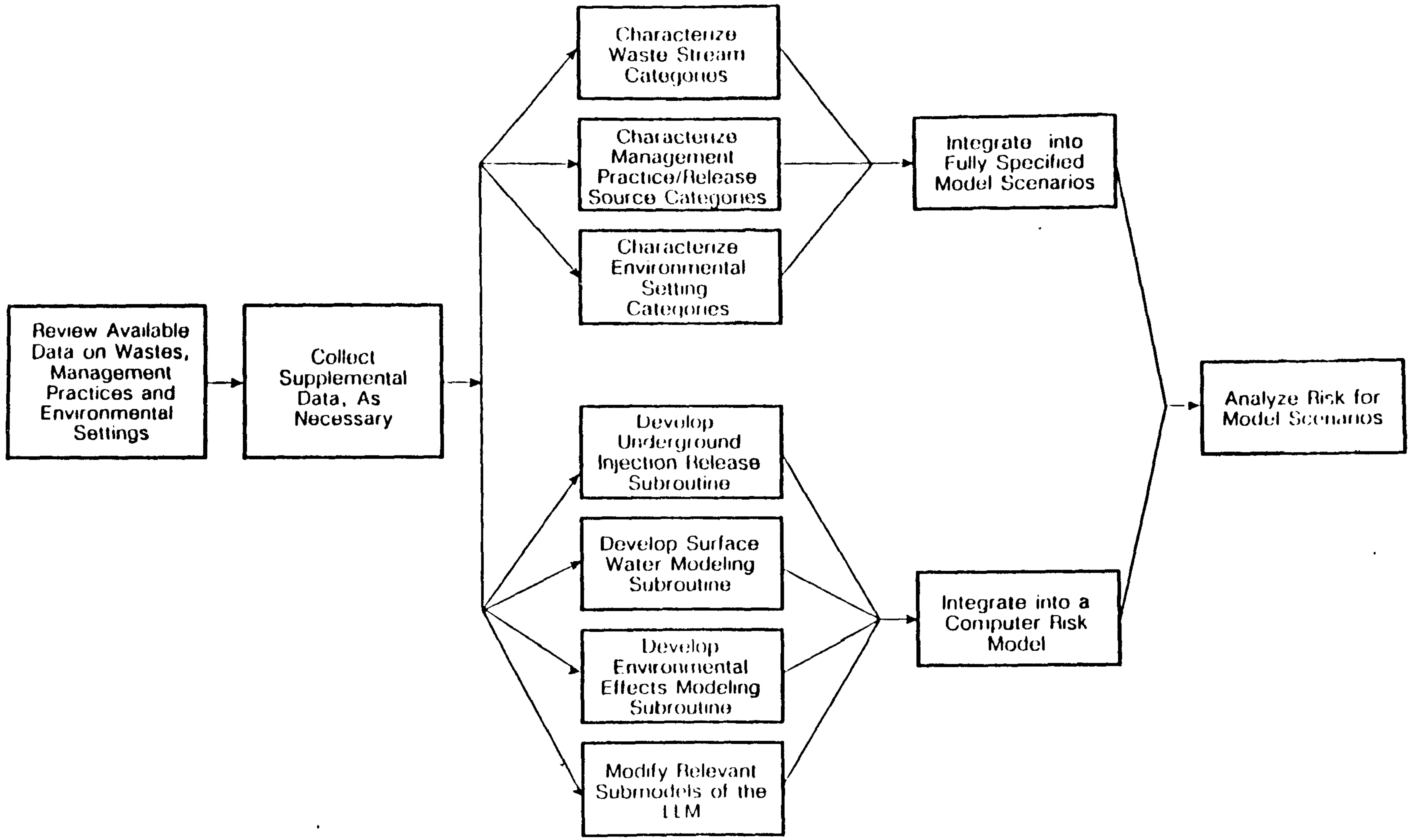

FIGURE IV-I. OVERVIEW OF THE RISK ASSESSMENT METHODOLOGY the generic approach is development and specification of model scenarios (i.e., hypothetical facilities) to cover the range of important risk influencing variables. Essentially, scenarios are unique combinations of subcategories of important variables that are specified in sufficient detail to allow risk estimation. The model scenarios for this analysis will be derived from actual data on wastes, management practices, and environmental settings.

Although the model scenarios will not represent individual real sites, they will represent groups of similar real facilities in the analysis. Generally, the more one disaggregates an analysis of this type (i.e., the more variables one considers and the more subcategories they are divided into), the more precise the results will be. A larger number of variable subcategories means that each subcategory can better represent a smaller number of real facilities. However, the data input requirements, modeling complexity, and analytical requirements also increase substantially with the level of disaggregation. Therefore, the design of a generic risk analysis such as this must account for the tradeoffs between analytical precision requirements and project scope. The proposed generic risk assessment framework provides an appropriate level of detail and disaggregation to address the objectives listed in Chapter 1.

As part of the model scenario development, the Agency will attempt to estimate the frequency of occurrence of each scenario. For example, suppose that 10 percent of the facilities of interest are in ground-water category A, 20 percent in category B, and 70 percent in category C. This would allow the Agency to evaluate the representativeness of the scenarios and to weight the eventual risk estimation results by frequency.

In parallel with the development of model scenarios, EPA will be developing, refining, and integrating the analytical tools necessary to quantitatively estimate chemical release, transport, exposure, health risk, and environmental effects. Existing OSW models will be adapted to the extent possible, especially the Liner Location Risk and Cost Analysis Model (LLM) (U.S. EPA, 1985a). The LLM is a fully computerized model that calculates health risks and contaminated ground-water volumes caused by chemicals released from land disposal facilities. The LLM was developed primarily for efficient analysis of large numbers of model scenarios (as opposed to rigorous analysis of site-specific risk) and thus is well-suited to the proposed approach. It will, however, need significant supplementation in three areas:

- Estimating chemical releases from underground injection;
- Modeling chemical transport/fate in surface water; and
- Modeling potential environmental effects (other than contaminated ground-water volumes).

As part of the oil and gas and geothermal energy risk analysis, EPA will develop technical approaches to these three modeling areas, and then integrate them into the LLM. Substantial alterations to the LLM surface impoundment release submodel may also be necessary to make it more applicable to treatment and disposal pits at oil and gas and geothermal sites. The Agency plans to use the current ground-water transport, human exposure/risk, and plume volume submodels of the LLM with limited adaptation.

In summary, there are two major parts of EPA's methodology leading up to the actual risk calculation step: scenario development and model development. Model development will produce the analytical tools necessary to estimate quantitative risks, while scenario development will provide the model inputs necessary to do the risk estimation. Of course, these two components are closely related. Modeling tools are needed only for significant scenarios, so the waste/source/setting characteristics of the industry largely determine the emphasis in the model development effort. Likewise, the specific equations selected as analytical tools dictate the variables that must be specified within scenarios. For instance, a complex ground-water model with substantial input data requirements would necessitate a much greater level of scenario specification than a simpler model. Thus, the two key parts of the approach should be viewed as complementary.

The final step in the methodology is actually analyzing risks of the scenarios using the modeling tools developed. In particular, the Agency will estimate incremental chronic human health risks (cancer and noncancer), that is, those effects due specifically to exposures to the waste constituents being assessed, exclusive of background exposures, and also the environmental damages for each realistic scenario. There will be no attempt to factor background exposures into the risk estimates as part of this analysis.

ALTERNATIVE METHODOLOGIES CONSIDERED

EPA believes that a generic risk assessment as described in this section of the report will satisfy the requirements of Section 8002(m)(1)(C), which directs EPA to analyze the "danger to human health and the environment from surface runoff or leachate" from oil and gas and geothermal exploration, development, and production activities. Section 8002(m)(1)(C) does not stipulate that quantitative risk estimates be developed, nor does it require a site-specific assessment. The Agency believes that the proposed generic methodology, which will incorporate available data on the industry but will not require extensive new data gathering, can be used to assess risk on an overall National basis and to identify patterns of risk relative to a number of important risk influencing factors. In addition, this study should provide preliminary quantitative estimates of individual risks and certain types of environmental damage, which can be refined with additional data collection.

EPA considered and rejected several other methodologies for this study. The principal alternatives and the reasons these methodologies are not being proposed are:

- <u>Detailed exposure and risk analysis of a statistically representative sample of actual sites</u>. This type of analysis would probably provide the most reliable results, but it would be impossible to carry out at this time because of extensive gaps in the available data. A comprehensive, site-specific risk analysis of a representative sample of sites would be a very large project even if all necessary input data were available. Therefore, this alternative was rejected because sufficient site-specific input data are not available and would be extremely time-consuming and expensive to collect.

- <u>Worst-case exposure and risk analysis of a sample of actual sites</u>. This type of analysis would be similar to that described above, but many site-specific parameters would be set based on conservative assumptions. It would still require an extensive, site-specific data collection effort, and the worst-case assumptions would blur distinctions that may exist among sites. Risk estimates tend to converge in these types of studies, making it more difficult to assess the effects of important factors such as waste type or hydrogeology on risk.

- <u>Detailed case study of a few sites</u>. This type of analysis would provide reliable information on five to ten sites, but is too narrowly focused to meet the needs of Section 8002(m) and therefore was rejected. Case studies would not give any information on the range or pattern of risks across the Nation as a whole.

The Agency believes that the proposed generic approach best meets the needs of the Section 8002(m) study. It will incorporate available industry data on wastes, management practices, and environmental settings, but will not require massive field data collection for specific sites.

CHAPTER 3

INPUT DATA FOR THE ANALYSIS

This chapter identifies the major data inputs needed for the risk analysis and the anticipated sources for these data. A comprehensive risk assessment requires the availability of substantial amounts of data on wastes, releases, and settings. To illustrate this point, Table IV-1 is a partial list of data that would be useful for this assessment of oil and gas and geothermal energy operations. Table IV-1 also identifies potential sources for many of the key data elements. Acquisition of some of these data elements is beyond the scope of this project, however, and EPA plans to make assumptions where necessary to supplement the available data.

Much of the information necessary for risk assessment is being collected, at least in the form of raw data, in other parts of the Section 8002(m) study. In particular, EPA is gathering and analyzing relevant data on the numbers and locations of facilities in the industry, types and volumes of wastes generated, physical and chemical characteristics of significant waste streams, and current waste management practices. The Agency will rely largely on these data in developing model scenarios to represent the industry. Thus, the risk assessment itself involves little primary data collection in areas of wastes and release sources. A limited research effort to characterize the environmental settings of oil and gas

Table IV-1. Oil and Gas and Geothermal Energy Development and Production Risk Assessment: Potential Data Needs and Sources

Data element	Potential data source
I. Production site/waste management system	
A. General	
* 1. Location of sites	a
2. Size, shape of sites	a
* 3. Description of waste management system components	b
* 4. Downgradient distance to site boundary	a
5. Surrounding land uses	a,d,f
6. Operating period	a
B. Surface impoundments (pits)	
* 1. Number/types of pits	a,b
* 2. Size, shape, depth, residence time, annual flow	b
3. Subgrade permeability, clogged layer permeability, and thickness	b,f
* 4. Basic design features (e.g., liners/liner permeability, leachate collection, leak detection, cover)	b
* 5. Effluent discharge rate/point	b
6. Monitoring plan/data	b
7. Closure and post-closure care practices	b
C. Underground injection	
* 1. Number/types of injection wells	a,b
2. Size of well/injection volume	b
* 3. Basic design features	b
* 4. Discharge depth	b
5. Monitoring plan/data	b
6. Closure and post-closure care practices	b
D. Other potentially significant waste management system components (e.g., land application, storage tanks)	b

Table IV-1. (continued)

Data element	Potential data source
II. Wastes (drilling muds, brines)	
* A. Total volume and volume per well	a,b
B. Volume per unit of production	a,b
* C. Chemical constituents and their concentrations	c
-- inorganics, including metals	
-- organics	
* D. Physical characteristics of the waste stream	c
-- solids (total and suspended)	
-- density	
* E. Treatment/disposal sequence and process description	b
F. Physical/chemical and toxicity characteristics of chemical constituents	e
-- partition coefficients	
-- degradation rates	
-- solubility	
-- toxicity parameters (e.g., threshold, potency)	
-- bioaccumulation factors	
III. Environmental Setting	
A. Hydrogeology	e,f
1. Ground-water flow direction	
* 2. Ground-water velocity	
* 3. Depth to ground water (water table)	
4. Hydraulic conductivity	
5. Porosity	
6. Gradient	
7. Fraction organic carbon (foc)	
8. Bulk mass density	
9. Subsurface stratigraphy (number of layers, depths)	
10. Soil type (of each layer)	
11. Ground-water quality data	
12. Seismicity	

Table IV-1. (continued)

Data element	Potential data source
13. Fractures/faults	
14. Hydraulic connections between injection zone and surface aquifers	
15. Ground-water class	
16. Other (e.g., unusual ground-water conditions)	
B. Surface water	f,g
* 1. Distance/direction to surface water bodies (from site)	
* 2. Type of surface water (perennial stream, river, lake)	
3. Streams	
* -- Flow rate	
-- Size (width, depth)	
-- Downstream system description (what it flows into, where)	
4. Lakes	
* -- Size (width, length, depth, volume)	
-- Turnover rate	
5. Surface water quality data	
6. Use classification	
C. Meteorology	e,f
1. Precipitation, net infiltration	
2. Severe storm frequency	
3. Flooding frequency of site	
D. Potentially exposed populations	
Ground water -- human	f,h
* 1. Distance to nearest downgradient well(s)	
2. Number of downgradient wells within 5 miles	
* 3. Site vicinity (USGS) map with well locations	
4. Public/private designation	
5. Water supply fraction	
6. Well depth	

Table IV-1. (continued)

Data element	Potential data source
Surface water -- human	f,g,h
* 1. Distance to nearest intake/each surface water	
2. Distance to all downstream public supply intakes	
* 3. Use of each intake (e.g., public supply, irrigation)	
4. Water supply fraction	
5. Other significant point sources nearby	
Surface water -- ecological	f
1. Ecosystem description	
2. Sensitive species/critical habitats	

* Key data element for proposed methodology.

a. Current EPA research on sources and volumes of wastes that is being conducted as part of the Section 8002 study.

b. Current EPA research on waste management practices that is being conducted as part of the Section 8002(m) study.

c. Current EPA waste stream chemical analysis that is being conducted as part of the Section 8002(m) study.

d. EPA damage case studies that are being compiled as part of the Section 8002(m) study.

e. LLM data bases (supplemented with additional chemicals, if necessary).

f. Mapping and literature surveys correlating site locations with environmental variables.

g. USGS (e.g., REACH files) and EPA (e.g., STORET) surface water data bases.

h. Population and drinking water data bases (e.g., GEMS, FRDS).

and geothermal energy facilities will be conducted at a level of detail consistent with the waste and release source data and the modeling techniques. Some directly applicable environmental information, such as maps of net infiltration categories and locations of sensitve environmental settings, has been developed and used in recent projects by EPA and is readily available.

One other significant source of information useful to the risk assessment is the compilation and analysis of damages attributable to oil and gas and geothermal energy facilities. The damage case summary currently being conducted as part of the Section 8002(m) study will provide information on the types and severity of damages attributed to past releases of contaminants from these facilities. It should also provide some information on the kinds of wastes, chemicals, and management practices involved, as well as whether the release was intentional (e.g., permitted effluent) or a result of technology failure. EPA plans to use information from the damage case reports to identify important exposure pathways, especially in the area of environmental (non-health) effects, and to confirm that its final methodology addresses these significant pathways. The analysis will not eliminate consideration of potentially important pathways simply because they are not frequently reported in the damage cases; one would not expect pathways with hard-to-measure endpoints (e.g., health effects of chronic exposures, ecosystem-level aquatic effects) to be reported frequently.

CHAPTER 4

INDUSTRY CHARACTERIZATION AND CLASSIFICATION

To initiate this risk assessment, EPA will analyze and organize relevant data on the industry's waste generators, waste stream types, release sources, and environmental settings. Characterizations will be based largely on the primary research and analysis being conducted for this Section 8002(m) study. The Agency will first develop appropriate categories of waste generators, waste stream types, release sources, and environmental settings based on these characterizations. The initial industry characterization and classification is discussed in this chapter. Then, for each waste generator subcategory, EPA will develop model scenarios of the waste stream, release source, and environmental setting to represent current practices in the industry and to serve as the basis for quantitative risk modeling. The development of model scenarios is described in Chapter 5 of this part.

WASTE GENERATORS

After organizing and reviewing the data on sources and volumes of waste (see Part I), EPA will divide the industry into appropriate categories for risk modeling. For example, waste generators may be divided into two main categories, oil and gas operations and geothermal energy operations. Each main category can be subdivided into production operations and developmental operations (drilling) and then further subdivided into active operations and inactive operations. It may also prove useful to classify generators as large-volume and small-volume operations, and to estimate the number of generators and the locations of facilities in each subcategory, based on the data collected in other parts of the overall study. These steps will produce a list of waste generator subcategories, with estimates of the numbers and locations of each.

WASTE STREAM TYPES

EPA will review the chemical analysis data being generated in another part of the Section 8002(m) study (see Part I) to identify significant waste stream types for each waste generator subcategory. It will then be possible to determine waste stream significance based on volume, number of generators, toxicity, and release potential. The intent will be to identify all wastes that are major contributors to health and environmental risk on a national basis, as opposed to all wastes that could potentially produce high risk in a few situations. The risk analysis will be based primarily on the waste streams included in EPA's current sampling and analysis program, in which samples are being collected from nine oil and gas producing zones of the United States.

The Agency will also estimate, to the extent possible, the distribution of waste streams across waste generator subcategories, release sources, and location. EPA will compile a listing of potentially toxic constituents for each significant waste stream type identified, and may review published reports to identify "high-risk" constituents that may be present in industry waste streams but not found in those sampled during this study.

For each significant waste stream type identified, it will be possible to develop at least one representative waste stream for modeling purposes. If waste characteristics differ subtantially across the nine sampling zones, multiple representative streams will be developed. For example, three different representative drilling muds corresponding to various geographic zones might be modeled. The representative streams will be defined by physical form and constituent identity and concentrations based primarily on the EPA sampling data. The analysis will also review the sampling data to identify waste streams whose constituents and/or constituent concentrations vary substantially from the representative streams.

After identification of significant waste streams in the industry, the next step will be to identify constituents of concern for the representative streams. Constituents of concern will be selected from the list of all waste stream constituents based on concentration, toxicity, persistence, and mobility in the environment. The LLM chemical data base will be the primary source used to rank toxicity, persistence, and mobility, and concentration data will be obtained from the EPA sampling report. Quantitative scoring algorithms will not be used to select constituents; instead, EPA plans to rank and evaluate the constituents in a waste stream based on the factors listed above and to make the final selection based on professional judgment. In general, the Agency expects to select from two to six constituents per stream for risk modeling purposes. The Agency may find it necessary to expand the list of constituents to address potential environmental effects adequately. Based on the Agency's prior experience modeling hazardous waste streams, most of the quantifiable risk associated with streams is usually due to one or two constituents. If those can be identified, it is unnecessary to include all chemical constituents in the full risk modeling.

The output of this step will be a limited number of representative waste streams (no more than ten) and constituents of concern for risk analysis. Each representative waste stream will be defined in terms of its physical and chemical characteristics, and its disposal amount and distribution across waste generator types and locations will be estimated.

WASTE TREATMENT, STORAGE, AND DISPOSAL PRACTICES/RELEASE SOURCES

The next step will be to review the waste treatment, storage, and disposal technologies employed in the oil and gas and geothermal energy industry. Significant practices are being identified and assessed in another part of this study (see Parts I and II). EPA will estimate each technology's distribution across waste generator subcategories, waste stream types, and locations. From this information, the Agency will identify the potentially significant sources and mechanisms of chemical release to the environment for each waste stream type. These significant release sources (e.g., surface pits) will eventually be the starting point for risk modeling. The Agency will also identify low-frequency/low-volume release sources that appear to have an unduly high potential for release into the environment.

After reviewing the waste management information, the next step will be to divide the identified release sources for modeling into appropriate categories such as underground injection wells and surface pits. Some release sources may be subdivided by size and/or design characteristics (e.g., presence of a liner), because these variables can affect the timing and magnitude of chemical releases and, therefore, the risk. It may also be necessary to subdivide to represent the range of existing practices in the industry adequately. For example, centralized treatment and storage facilities, such as surface pits, are common in the industry and may be much larger than typical units found at individual sites.

For each release source category, the Agency will identify potential mechanisms of release such as effluent discharge to surface water or seepage into ground water. The result will be a list of subcategories of release sources along with their potential mechanisms of release. It may also be possible to estimate the distribution of release sources across generators, waste stream types, and locations.

ENVIRONMENTAL SETTINGS FOR RELEASE SOURCES

The environmental setting of a release source location is an important factor that influences risks associated with the release of waste materials. In general, the analysis will develop values for significant environmental variables based on this project's research and on a review of readily available information generated as part of other relevant projects (e.g., the Subtitle D risk analysis, the cross-program regulatory analysis, other applications of the LLM, and applications of the RCRA Risk-Cost Analysis Model).

The first step in characterizing environmental settings will be to estimate the number and general distribution of facilities within each major oil and gas and geothermal energy Region. Much of the information needed to complete this step will come from EPA's research into waste generators, waste stream types, waste management practices, and damage cases. If necessary, however, these research results can be supplemented with additional data available in the literature. For example, the Independent Petroleum Association of America (1986), the American Petroleum Institute (1986), the Department of Energy (1985), the Colorado School of Mines (1983), and the Rand Corporation (1981) provide useful data on the number and distribution of oil and gas sites. Next, the analysis will characterize the principal environmental risk variables for each of the major Regions as a whole. Facilities within each Region will then be assigned the distribution of environmental variables for the respective Regions. Although this approach will not involve a site-specific analysis of all sites, the Agency believes it is justified because of the sheer number of sites involved (in 1985, there were approximately 870,000 onshore oil and gas wells) and because it believes that a Regional as opposed to a site-specific analysis will yield reasonably accurate results (available information indicates that most sites are clustered in certain Regions). EPA will develop a distribution of values across release source locations such that, for each environmental variable, it will have at least two values: a typical or average value and a more conservative value that will yield higher, but not necessarily worst-case, risk estimates.

Important risk influencing environmental variables are described below under the categories of climate, hydrogeology, surface water, human exposure points, and environmental exposure points. Each section identifies the necessary individual data items required to characterize environmental settings, and outlines the Agency's approach for obtaining values for these data.

Climate

Net annual infiltration rate is an important variable that will be used to characterize climate. Net infiltration affects the rate and extent of ground-water contamination from some types of release sources, including landfills and land treatment operations. EPA will develop a distribution of values for this variable based on an analysis of the Regions in which most of the oil and gas and geothermal energy facilities are located.

As part of OSW's LLM project, four net infiltration regimes (0.25 inch, 1 inch, 10 inches, and 20 inches, respectively) that are representative of the different conditions found in the U.S. have been developed from a previous literature review. These net infiltration regimes have been assigned to different Regions across the U.S. For this project, EPA plans to develop a distribution of net annual infiltration rates for oil and gas and geothermal energy sites based on the locations of the Regions that contain most of the relevant sites. This approach will be consistent with the method the Agency has used to assign net annual infiltration rates to hazardous waste facilities as part of other projects (e.g., the 118 hazardous waste land disposal facilities in the LLM's real facility data base and the 55 facilities examined as part of the cross-program regulatory analysis).

Hydrogeology

The primary hydrogeologic variables of interest to this project include ground-water velocity, depth to ground water, hydraulic conductivity, and various soil properties used to assess contaminant retardation (effective porosity, bulk mass density, and fraction of organic carbon). In addition, information on the occurrence and nature of any layering within the saturated zone (i.e., stratigraphic data) will be required if the Agency decides to characterize more complex ground-water flow systems. All of these variables influence risks by dictating the potential for contaminants to migrate through ground water to points of exposure. In past analyses using the LLM, EPA has focused on the upper layers of ground-water systems; however, oil and gas wastes are often released into deeper strata using injection wells. Information in the damage case studies will be used to determine whether significant exposures to wastes released in the injection zone are common and, if so, additional hydrogeologic parameters needed to characterize deeper strata will be identified. At this time, however, the Agency does not plan to model transmission of contaminants from deeper strata to upper layers of ground-water systems because (1) there are no simple models to use, and (2) acquiring the stratigraphic input data to assess this pathway is beyond the scope of this project.

EPA will develop a range of values for several of the required hydrogeologic variables using the National Water Well Association's "DRASTIC" system (National Water Well Association, 1985). This system divides the U.S. into hydrogeologic Regions and provides generally recognized values within each Region for several variables related to contamination potential. Superimposing these DRASTIC Regions onto the Regions containing the majority of oil and gas and geothermal energy activity will yield data on the depth to ground water, aquifer media type, and unsaturated zone media. Once the media in the aquifers and unsaturated zones are defined, the Agency will select a range of values for hydraulic conductivity, effective porosity, and bulk mass density based on typical values for these parameters reported for different soil types. For example, Codell and Duguid (1983) provide tables of values for hydraulic conductivity and effective porosity, and Hough (1957) reports typical bulk mass density values for a wide range of earth materials.

Eleven ground-water flow field scenarios have been developed to represent the majority of ground-water flow conditions in the U.S. These scenarios, which define various combinations of ground-water velocities (ranging from 1 meter/year to 10,000 meters/year) and aquifer-aquitard layer sequences within the saturated zone, are used in the LLM to model ground-water flow. Because the Agency will use the LLM to analyze ground-water fate and transport (see the discussion in Chapter 6 on modeling techniques), the values for ground-water velocity and the aquifer configurations developed for this project will be confined to those specified in the 11 flow field scenarios of the LLM.

To determine the appropriate distribution of flow field scenarios for this project, ground-water velocity data and aquifer configuration information given in the DRASTIC system for the major oil and gas and geothermal energy producing Regions will be examined. Combining the facility location information with hydrogeologic data from DRASTIC (i.e., estimating densities of facilities per DRASTIC subregion), will yield a frequency distribution for the variables of interest. It should be emphasized that the Agency does not intend to use the DRASTIC scoring procedures, but only the hydrogeologic data for various subregions. As a check to this approach and to fill in any data gaps, two additional methods for assigning flow field scenarios will be pursued. The first will be to examine flow field scenarios previously assigned to other facilities located in the various oil and gas and geothermal energy Regions (e.g., the 55 facilities examined in the cross-program project, the 118 facilities in the LLM's real facility data base, and the 67 sites examined to develop the LLM's generic flow field scenarios). The second will be to examine U.S. Geological Survey (USGS) topographic maps for a sample of facilities to determine a range of hydraulic gradients which will be ascertained by assuming the ground water underlying a site has the same gradient as the land surface slope. These values for hydraulic gradient will be used to calculate ground-water velocities using Darcy's Law, an expression that relates ground-water velocity to the hydraulic gradient, hydraulic conductivity, and effective porosity (a determination based on predominant soil types as described above).

Surface Water

Surface water data are needed to determine direct impacts to surface water resources as well as human and ecological exposures through surface water intakes. Although the methodology for modeling chemical transport in and damage to surface waters has not yet been finalized (see Chapter 6), EPA expects that the data needs will include the type (e.g., lake, river), location, size, flow rate, and patterns of use of nearby surface waters.

Based on the Agency's current knowledge, the occurrence, nature, and patterns of use of surface waters surrounding oil and gas and geothermal energy production facilities are highly varied across the universe of facilities. Therefore, rather than attempt to rigorously define the distribution of key surface water variables across all sites, EPA will simply define for each variable a set of values that are reasonable for the major oil and gas and geothermal energy Regions. It will then be possible to combine different values for each variable to form a variety of surface water scenarios. As a means of illustration, the following is a listing of surface water variables and a possible set of values for each:

- Distance from facility to nearest surface water body: $\leq$ 0.5 mile, between 0.5 and 2 miles, and $\geq$ 2 miles;
- Stream flow rate: 10, 100, and 1,000 ft^3/sec; and
- Patterns of use: human consumption only, recreational uses (e.g., fishing and swimming) only, and combined consumption and recreational uses.

To derive a reasonable set of values for important surface water variables, the first step will be to examine State hydrologic unit maps for those States where the majority of oil and gas and geothermal energy facilities are located. These maps show the position and size of principal streams, rivers, and lakes. Distances of facilities from these surface water bodies can be estimated by superimposing the general distribution of facilities onto these hydrologic unit maps. Other information sources are available for determining values for other surface water variables. For example, the USGS's National Water Data Exchange, Master Water Data Index, REACH Files, and Water Data Storage and Retrieval System all contain values for water body-specific data. Similarly, EPA's Stream Gage Inventory File and STORET Flow File contain stream flow rates for thousands of stream gauging stations throughout the country. Data in these information systems will be examined only at a level of detail that will enable EPA to develop a representative distribution of values for the major oil and gas and geothermal energy Regions.

Human Exposure Points

Potentially exposed populations will be characterized by examining the distance and direction to human exposure points in the vicinity of a sample of facilities. The Agency does not plan to estimate rigorously the number of people potentially exposed at any specific site nor to develop projections of the total exposed population. EPA also intends to emphasize exposures through the ingestion of contaminated ground and surface waters; the Agency may expand the analysis to consider other exposures including ingesting of contaminated fish and inhalation. However, air exposures will be considered if waste release and damage case information indicates that the airborne pathway should be addressed. Once sufficient exposure point data have been developed for a sample of facilities, EPA will extrapolate these results to estimate the distribution of distances to human exposure points across all facilities. The assumptions and uncertainties associated with this extrapolation will be fully described in project reports.

To determine the distribution of human exposure points through ground water, the first step will be to locate a sample of facilities on USGS topographic maps and to estimate the direction of ground-water flow from the site by assuming the ground water flows in the direction of the predominant land surface slope. Next, the area of potential contamination will be defined as the area $\pm$ 45 degrees of the center line of ground-water flow and out to some specified distance, such as one or two miles. Finally, EPA will attempt to determine whether drinking water wells are located within this area of potential contamination. Telephone interviews with local officials are the most reliable source of well location information. EPA has used this mapping/telephone interview approach for estimating exposed populations in several other recent projects, including development of the LLM data base and the OSW cross-program regulatory analysis.

Potentially contaminated surface water resources will be defined as those bodies of water that (1) are located within the potentially contaminated ground-water area; and/or (2) are known to receive liquid effluents from an oil and gas or geothermal energy facility. The Agency plans to identify the surface waters potentially contaminated by ground-water seepage through the USGS map procedure outlined above, and may, for a sample of facilities, identify surface waters receiving direct discharge by conducting telephone interviews with State officials who oversee National Pollutant Discharge Elimination System (NPDES) permits. In addition, the Agency plans to estimate the distance to surface water intakes (if any) for human consumption.

Environmental Exposure Points

The methodology and information requirements for modeling environmental exposures will be finalized after some initial data gathering is complete. This section, therefore, describes the general information requirements for an assessment of environmental damage or ecological risk.

An ecological risk assessment requires the development and examination of two general types of data: toxicological hazard data and environmental exposure data. Environmental toxicity data reflect the potential for a constituent to cause an adverse effect under a particular set of conditions. Adverse effects can include mortality to single species of organisms; reductions in populations of organisms caused by acute, chronic, and reproductive effects; and disruption in community and ecosystem level functions (EPA, 1986c). Common toxicological data used in assessing environmental risks would include LC_{50} and LD_{50} values and no-effect levels for certain critical species. Environmental exposure data include the estimated environmental concentration of a contaminant, as well as the numbers, types, and distribution of organisms exposed to the environmental concentrations.

In general, the Agency plans to collect toxicity data from a review of the general literature (e.g., EPA's Ambient Water Quality Criteria Documents; Curtis et al., 1979; and Stickel, 1974) and from discussions with relevant scientific and government organizations (e.g., EPA, the Department of the Interior's Fish and Wildlife Service, and academic research institutions). In particular within EPA, the Office of Pesticide Programs' Ecological Effects Branch, the Office of Water Regulations and Standards, and the Corvallis Environmental Research Laboratory have been active in examining ecological toxicity data and should prove useful for this type of information. In addition, EPA has compiled environmental toxicity data for a variety of contaminants in order to develop the ecorisk submodel of the RCRA Risk-Cost Analysis Model (EPA, 1984b).

Although most ecological toxicity data have been developed on a chemical-specific basis in the past, considerable testing has been done in recent years on intact effluents and wastes. Some of this type of data exists for wastes associated with oil and gas operations (Gaetz et al., 1986; EPA, 1984a). The feasibility of using such a waste-based approach for assessing ecological effects will be examined as a means of supplementing the chemical-specific approach.

Data on contaminant concentrations in environmental media will be calculated based on the modeling approach (for surface and ground waters), and/or estimated based on available environmental monitoring data from actual facilities. Rather than attempting to precisely define the numbers, types, and distribution of potentially exposed organisms, the analysis will examine the risks to hypothetical exposed organisms of one or more indicator species. The Agency will select appropriate indicator species based on such factors as the availability of toxicity data for the species, the sensitivity of the species to constituents of concern, the likelihood of exposure of the species to oil and gas and geothermal energy wastes, and the aesthetic and/or economic importance of the species. For this type of information, EPA will consult experts and standard reference materials (e.g., Lee et al., 1980; EPA, 1972; and Carlander, 1977).

In addition to modeling ecological risks on a chemical-specific basis, EPA will develop other measures of potential environmental damage such as proximity of oil and gas and geothermal activities to wetlands, sensitive areas, or endangered species habitats. The Agency also plans to estimate damage measures such as volumes of ground water and surface water contaminated and acres of land damaged.

To analyze potential damage to environmentally sensitive areas, the analysis will rely on existing maps and delineations of endangered species' habitats, wetlands, and other areas of interest. For example, in analyzing ecologically vital ground water as part of the ground-water classification guidelines, EPA mapped the environmentally sensitive areas in California and Louisiana, two major oil and gas producing States (EPA, 1986a). Other useful sources of information include 50 CFR Part 17, which identifies the historical range and critical habitats of threatened and endangered species, and experts within the U.S. Fish and Wildlife Service and State Natural Heritage Program Offices. Information on the locations of environmentally sensitive areas will be assembled only at a level of detail that will allow a rough approximation of the type and extent of potentially affected areas. The Agency will calculate approximate volumes of ground water and surface water contaminated through the modeling approach, but will rely primarily on the results of the damage case studies to estimate acres of land damaged.

CHAPTER 5

EXPOSURE PATHWAY ANALYSIS AND MODEL SCENARIO DEVELOPMENT

Once the characterization of wastes, release sources, and environmental settings is complete, the Agency will identify potential human and environmental exposure pathways (an exposure pathway is a unique combination of release source, environmental transport medium, exposure point, and exposure route). Actually, this step is a reassessment of the preliminary identification of significant pathways that is made early in the analysis. For example, the Agency has identified as a potentially important human exposure pathway releases of contaminants to ground water from surface pits, followed by ingestion via drinking water. EPA has also made the preliminary determination that pathways involving release to air will probably be relatively less important. The data collected in the industry characterization step will, however, be systematically evaluated to confirm the significance of exposure pathways identified earlier and to identify ones that may have been overlooked. EPA will develop a complete matrix of reasonable exposure pathways and will document the rationale either for including or excluding each from the risk analysis.

Although dozens of potential exposure pathways may be identified, the Agency emphasizes that it will only include a few in the quantitative modeling and risk analysis. Each additional pathway included increases the scope and complexity of the analysis. It is, therefore, important to identify and focus on the exposure pathways that are most significant in terms of risk. EPA will use two different approaches to identify important pathways. The first will be a review of the compiled information on waste types, waste management practices, and environmental settings for oil and gas and geothermal energy facilities in order to develop hypotheses about possible sources and mechanisms of contaminant release to environmental media. For each release source/release medium combination, the Agency will evaluate the possibility of transport to human or environmental exposure points, as well as the likelihood of intermedia transfers (e.g., ground water to surface water). The second approach will be to review the damage case summaries (see Part III). From these reported cases of damages attributable to oil and gas production operations, it will be possible to identify the chemicals and exposure pathways that have resulted in either adverse health or environmental effects.

After the exposure pathways for quantitative risk analysis are determined, the next step is to combine the major waste types, release sources, and environmental settings into realistic model scenarios for risk modeling. Essentially, this is a reorganization and refinement of the data collected in the industry characterization (see the discussion in the preceding chapter). Model scenarios, intended to represent actual current practices in the industry, will be arranged as a matrix with three primary dimensions -- waste type, source type, and environmental setting type -- with an as yet undetermined number of categories along each dimension. It may be possible, for example, to reduce the industry data to 10 composite waste types, 10 categories of release sources, and 20 environmental setting categories, for a theoretical total of 2,000 model scenarios for which risk would be estimated. It is also likely that the theoretical total in this example could be reduced considerably, because some combinations may be unrealistic (e.g., specific release sources may not be applicable to all waste types).

The final matrix of model scenarios defines what will be modeled in the subsequent risk analysis. The Agency will estimate a health risk and/or an environmental effects measure for each realistic cell in the matrix.

CHAPTER 6

DEVELOPMENT AND REFINEMENT OF MODELING TECHNIQUES

The LLM will be used as the predominant tool for estimating risks associated with oil and gas and geothermal energy facilities. In its current form, the LLM can assess human health risks associated with ground-water releases from surface impoundments and landfills. Because there are several other areas of interest in this project (e.g., releases from injection wells, surface water fate and transport, and environmental damage), it may be necessary to adapt the LLM and/or use other modeling techniques to supplement the LLM analyses. This chapter discusses the proposed general approach for modeling contaminant release mechanisms, environmental fate and transport, human exposures and health risks, and environmental damages. For more information about specific submodels of the LLM, refer to the most recent draft report (EPA, 1985a).

CONTAMINANT RELEASE TO GROUND AND SURFACE WATERS

At this time, EPA plans to examine at least three sources for release of oil and gas and geothermal energy wastes: underground injection wells, surface pits, and effluent point sources. Based on a review of the background information presently available to EPA, these disposal practices appear to constitute the principal release sources of concern. For this project, the Agency plans to model all releases deterministically;

stochastic failure and release models will not be developed or used. EPA anticipates developing several release profiles to represent the major mechanisms of failure, including low-probability, high-quantity failures, as determined by a literature review and engineering analysis.

Underground Injection Wells

In examining releases from injection wells, the scope of the analysis will be limited to releases to upper aquifers through failure of the injection well. At present, EPA does not intend to model risks from the emplacement of wastes in an injection zone, primarily because the Agency suspects that the health and environmental hazards are small if the wastes are confined to deeper formations. For example, the RCRA Risk-Cost Analysis Model only considers releases from injection wells that lead to the contamination of upper aquifers. However, EPA will examine its damage case studies to determine whether releases into the injection zone result in significant exposures and whether such releases should also be taken into account in this analysis.

In general, two main types of injection well failures that can result in releases to upper ground-water systems will be examined: well-head/piping failures and casing/grout seal failures. Well-head/piping failures involve the failure of a pump seal or a rupture of a pipe such that wastes are discharged directly to the ground surface. Although most of the wastes released in this way will be cleaned up, some fraction may be directed to surface water or seep into the ground. Casing/grout seal failures involve a deterioration of the well casing or seals, creating a hydraulic connection between the injectant and an aquifer. For this type of failure, a significant portion of the injected wastes may escape into an aquifer.

The Agency will model release volumes and estimate the frequency of occurrence associated with each of these release types. A probabilistic approach involving simulation modeling will not be attempted; instead, the Agency will develop "typical" injection well release scenarios based on case histories involving injection well failures. For example, it will be possible to estimate how many well-head/piping failures a typical injection well experiences over its operating life, what volume is usually released per failure, and what portion of the released volume is not cleaned up. It will then be possible to estimate the fraction of injection wells that result in releases as defined by this typical scenario. Such an approach is used to estimate releases from hazardous waste injection wells in OSW's RCRA Risk-Cost Analysis Model, based on data gathered through consultation with experienced engineers and injection well operators. EPA will explore the possibility of using the injection well release scenarios developed for that model in this project.

Surface Pits

For modeling chemical release from a surface pit, the Agency plans to adapt the unlined surface impoundment failure release submodel from the LLM. The LLM models release (1) during the active operating period, when the impoundment contains liquid and contaminant releases are driven by that liquid; and (2) during the period following closure, when the impoundment has been drained and covered and contaminant releases are driven by net infiltration. The model may need to be modified for drilling mud reserve pits because of the potential for clogging and sealing. Available information collected for this project indicates that the clay content of oil and gas wastes may in some cases reduce leachate release rates by lowering the permeability of drilling fluid pits. EPA plans to examine its waste stream and release source data (see Parts I and II) and other literature sources as needed to quantify this phenomenon; if necessary, the permeability or other assumptions will be adjusted so that the LLM submodel will be more similar to drilling mud surface pits at oil and gas and geothermal energy sites. EPA also plans to investigate other potentially applicable models, such as the Post Closure Liability Trust Fund Model (EPA, 1985b); Hydrologic Simulation on Solid Waste Disposal Sites (Perrier and Anthony, 1980); and a new release rate model being developed by OSW's Land Disposal Branch.

Effluent Point Sources

As discussed in Chapter 4, the risk analysis will identify significant waste streams for several waste generator subcategories. Based on the available waste stream data, it will be possible to develop typical source terms characterizing constituent concentrations and release rates for effluent point sources. EPA will thus assign source terms for effluent inputs to surface water based on the data review rather than through a predictive modeling approach.

CONTAMINANT TRANSPORT AND FATE

For this risk analysis, the Agency anticipates modeling chemical transport in two environmental media, ground water and surface water.

Ground Water

EPA will use the LLM's subsurface transport submodel to determine the transport and fate of contaminants of concern in ground water. That submodel predicts mass transport of contaminants through the unsaturated zone--the soil layer above the water table in which the pore spaces are only partially filled with water--and the saturated zone.

The LLM calculates the travel time for a released contaminant to pass through the unsaturated zone and reach an underlying aquifer using the modified McWhorter-Nelson wetting front model. The travel time is related to the difference in water content between the layer immediately above and below the front, the distance traveled in the unsaturated zone, the leakage rate, and the retardation of contaminant movement by soil adsorption. Unsaturated zone thickness, leachate discharge rate, and a chemical's retardation factor have the most effect on travel time. Key assumptions in the unsaturated zone transport component of the submodel are that no contaminant interactions occur and that one-dimensional (vertical, downward) modeling of the transport in the unsaturated zone is valid. EPA will address how these assumptions affect the final risk estimates.

The Agency will assess the transport of contaminants in the saturated zone and predict contaminant concentrations over time at distances downgradient of the release sources using the saturated zone component of the subsurface transport submodel. As discussed previously, concentrations of contaminants in ground water can be estimated for 11 generic flow fields.

The LLM estimates concentrations in the 11 generic flow fields with a modified version of the Random-Walk Solute Transport Model (Prickett, Naymik, and Lonnquist, 1981). Dissolved chemicals are treated as particles that move in two stages. First, each particle moves in the direction of ground-water flow, and then each particle disperses randomly based on values of exogenous dispersion coefficients. In the LLM, the basic random-walk model output is adjusted for several factors not rigorously modeled, including source strength, duration, and width; degradation; retardation; transverse dispersion; and dilution caused by pumping.

The LLM calculates a separate time profile of contaminant concentrations at the exposure point for each year of contaminant input to the saturated zone, and then sums these profiles to produce the overall time profile of concentration (i.e., breakthrough curve). As for the unsaturated zone model, key assumptions in the saturated zone component will be outlined and their effects on the final risk estimates will be evaluated.

Surface Water

The LLM currently models releases of contaminants to surface water via ground water, but it does not model the fate and transport of contaminants once they enter the surface water body. The Agency will therefore modify the LLM to incorporate a simple surface water model for this project. The Agency also intends to modify the LLM to consider direct releases to surface water.

The environmental fate of contaminants entering surface water bodies is dependent on the type of water body involved. In general, there are three predominant classifications of surface water bodies: rivers and streams, lakes and other impoundments, and estuaries. Based on the known distribution of oil and gas and geothermal energy sites, all three classifications may be important in assessing waste releases for this project.

For rivers and streams, the initial concentration of a constituent in the water is simply the mass loading (from either ground-water seepage or direct discharge) divided by the streamflow. To determine constituent concentrations downstream, the analysis will use a one-dimensional, steady-state model similar to the one proposed for use in the land disposal restrictions program:

$$C_x = C_0 e^{-K(x/U)}$$

where

C_x = Concentration at downstream distance x (mg/l)

C_0 = Concentration in stream after initial dilution (mg/l)

K = Decay rate constant for surface water (sec^{-1})

U = Mean stream velocity (m/sec)

x = Distance downstream (m).

The input data for such a model will be developed through an examination of existing data compilations and summaries available within EPA and from the USGS. There are several other simple river and stream models being evaluated for use in this project (e.g., equations available in Delos et al., 1984; Fisher et al., 1979; Liu, 1977; and Neely, 1982). While such models may have to be adapted for this analysis to consider oily wastes that do not mix completely with water, the Agency favors a simple surface water model for this analysis because such models provide useful predictions of contaminant concentrations without the substantial data inputs and resources needed to run more complex models (e.g., EPA's Exposure Analysis Modeling System).

There is great diversity in impoundment and estuary types, as well as a wide range of complexity in methods for predicting contaminant fates in these types of surface water bodies. Mills et al. (1982) identify and describe several estimation methods useful in impoundment and estuary assessment. EPA is currently in the process of evaluating these and other models for impoundments and estuaries.

EXPOSURE AND HEALTH RISKS

The LLM will be used to predict the human health risks from chronic exposure to contaminated ground water via drinking water. The LLM is capable of assessing both cancer and noncancer health risks.

Cancer Risks

Cancer risks will be estimated by using a linear (at low doses), non-threshold dose-response equation. The LLM uses the one-hit equation, which calculates the lifetime individual risk as an exponential (but linear at low doses) function of potency and lifetime average dose. Dose will have been determined from the release and transport submodels described in previous chapters. Potency is chemical specific and will be set equal to the the upper-bound unit risk parameter estimated by EPA's Carcinogen Assessment Group.

Chronic Noncancer Health Risks

Chronic noncancer health risks will be estimated with a dose-response model that calculates risk from noncarcinogens as a continuous function of dose at dose levels above a threshold. For this purpose, the LLM uses the Weibull equation with a threshold. The lifetime individual risk is an exponential function of several parameters, including the Weibull dose-response parameter, the lifetime average dose, and the threshold. Individual risk is considered to be zero below the threshold.

ENVIRONMENTAL DAMAGE

To assess the environmental damages caused by oil and gas and geothermal energy wastes, the Agency will examine potential adverse effects on ground water, surface water, land, and ecosystems. Because EPA believes that potential environmental damages are an extremely significant aspect of this study, and because some of these damages are not amenable to the chemical-based predictive modeling procedures to be used for health risk assessment, several assessment approaches will be employed for estimating environmental effects. EPA definitely plans to conduct a chemical-based analysis of model scenarios for some environmental damage endpoints. Specific endpoints to be assessed in this way include contaminated volumes of ground water and surface water, and exceeded aquatic ecosystem thresholds for individual chemicals. This model scenario approach will parallel the health risk analysis, and many of the necessary modeling components (e.g., chemical release and transport) will be identical. Thus, estimates will be available for both health risk and environmental damage for some of the model scenarios developed.

A second approach will be to use current information from damage cases to extrapolate observed environmental effects to the universe of oil and gas and geothermal energy sites. EPA will attempt to derive point estimates or distributions of relevant endpoints, such as contaminated acreage or crop damage, per well or per some other index of production. As a third approach, EPA intends to correlate locations of oil and gas and geothermal energy operations with locations of significant environmental variables, such as wetlands or critical habitats. EPA has used this approach in the Section 8002 mining waste study. These three approaches to analyze environmental damage are briefly described below.

Damage to ground and surface waters can be assessed by determining the volumes of water contaminated above certain thresholds such that the water is rendered unfit for human consumption, unfit to support aquatic life, or otherwise significantly less useful than before becoming contaminated. To assess the volumes of contaminated ground water from specific model scenarios, EPA will use the LLM, which is capable of estimating contaminant plume widths and volumes. Using the modified LLM, along with surface water damage thresholds for specific chemicals, the Agency will also estimate the volumes of surface water contaminated.

Estimating adverse effects to land must be carried out through methods other than chemical-specific modeling using the LLM. Documented cases involving damages to significant areas of land primarily involve releases of brines (i.e., chlorides). In several States, damage cases suggest that thousands of acres have been damaged or rendered useless from brine releases originating from oil and gas well sites. In one Region, for example, the average acreage lost as a result of oil and gas production activities has been reported as approximately 0.8 acre per brine pit. EPA intends to develop a distribution of factors, such as the one just presented, that relates the number of acres damaged per unit of waste release or waste management activity. Because most land damage cases involve and most information appears to be available for releases of brines, hazards to land will be assessed mainly by focusing on brines. In addition, EPA will have to define exactly what it means by "damaged"; it plans to develop a range of adverse effects to land to reflect different levels of damage.

Two complementary approaches to assessing ecosystem damages (a subset of overall environmental damages) are under consideration. The first would be a quantitative assessment of ecological risks for a set of model scenarios. As in health risk assessment, an ecological risk assessment is generally made up of four general components: hazard identification, dose-response assessment, exposure assessment, and risk characterization. The primary difference is that ecological risk assessments focus on aquatic and terrestrial indicator species rather than on humans. Barnthouse et al. (1982a and b) describe five methods for environmental risk analysis; the Ecological Effects Branch of EPA's Office of Pesticide Programs also has documented its approach to ecological risk assessment (EPA, 1986c). In addition, EPA's Office of Solid Waste has recently applied an ecorisk scoring system for hazardous wastes (EPA, 1986b), and EPA's Integrated Environmental Management Division (IEMD) has applied an ecological effects assessment procedure for specific chemicals. These methods are under consideration for use in this project.

As an alternative approach to examining ecosystem damages, EPA will investigate the proximity of endangered species habitats, wetlands, and possibly other sensitive environmental areas to oil and gas and geothermal energy facilities. The Agency will determine the proximity of sensitive areas by mapping the general distribution of wetlands and endangered species habitats relative to the major oil and gas and geothermal energy regions. This analysis, combined with results concerning the volumes of water contaminated and acres of land damaged, will form the basis for qualitative conclusions about the hazards to these sensitive environments.

CHAPTER 7

ANALYSIS OF SCENARIOS

In this final major step of the risk analysis, EPA will apply the modeling tools developed to estimate health risks and potential environmental damages for the complete set of reasonable model scenarios. This step will produce the quantitative risk modeling results of the Agency's analysis, and will form the basis for its conclusions about potential health risks and environmental effects. EPA will probably use an integrated computer model, adapted from the LLM, to do the necessary calculations for the large number of model scenarios.

The outputs of this step will be a quantitative measure of health risk and/or environmental effects for each realistic scenario in the waste/source/environmental setting matrix and, if possible on the basis of available data, an estimate of the distribution of actual facilities across scenarios. This type of result would provide information on both the frequency and intensity of potential adverse effects from oil and gas and geothermal energy facilities. The Agency will then be able to rank scenarios on the basis of the risk and identify extremely high-risk and low-risk combinations. It may be possible to construct relative risk rankings of individual factors, such as waste type or source type.

EPA does not plan on presenting precise point estimates of absolute risk using the generic methodology described in this chapter. Instead, it plans to present the results as both weighted (by frequency) and unweighted frequency distributions of individual health risk (or environmental damage) across various combinations of model scenarios. For example, a risk distribution across all scenarios might be developed first; the data might then be disaggregated into numerous distributions across subsets of scenarios (i.e., if there were ten waste stream categories, the analysis would develop and compare the risk distributions for each). Figure IV-2 illustrates the type of frequency distribution that will result from the risk analysis.

Clearly, many assumptions will be necessary to carry out the quantitative analysis of risks. EPA plans on testing the potential effects of major assumptions through a sensitivity analysis, varying the values assigned to key parameters over their reasonable range, and determining the effects on the risk measures used.

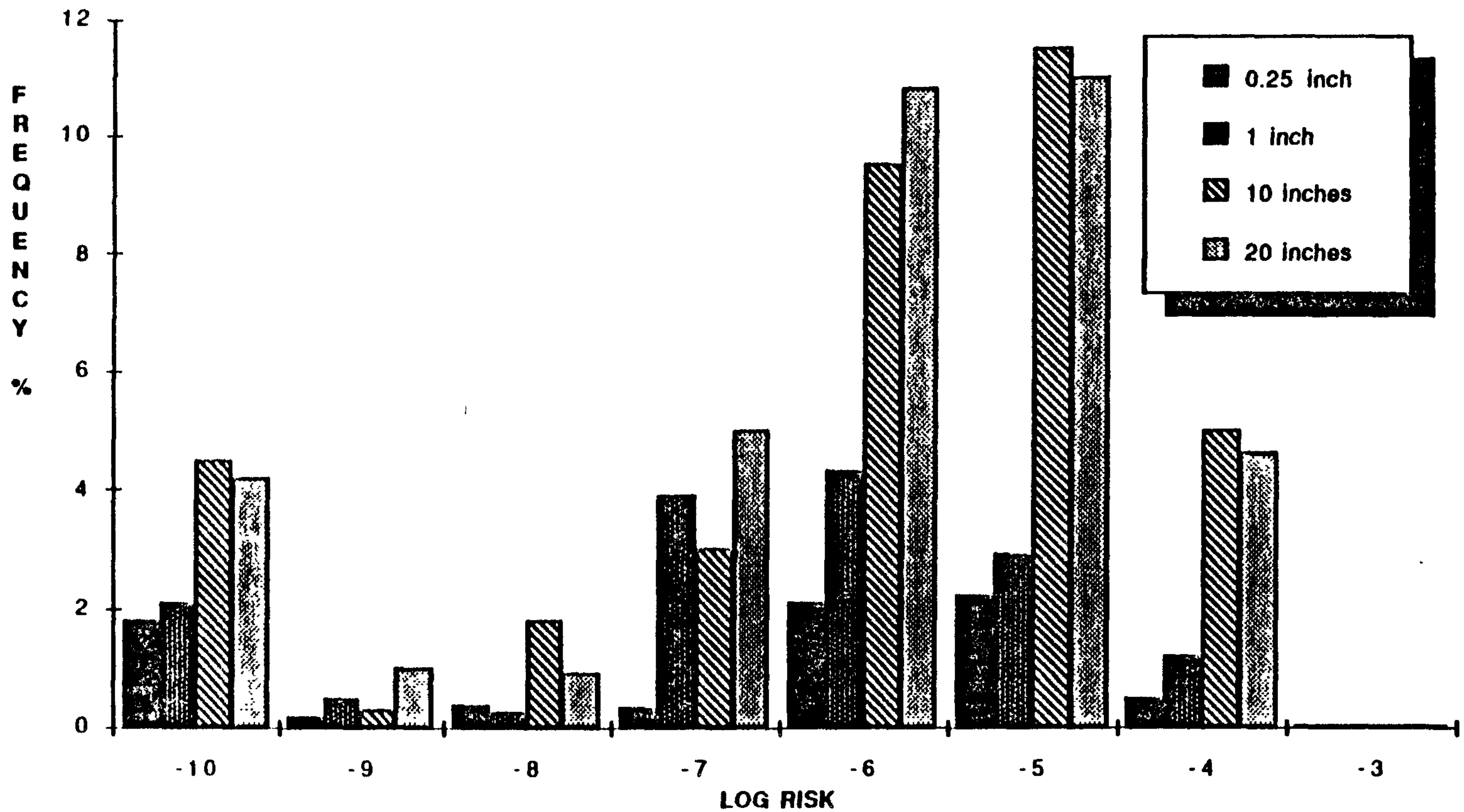

FIGURE IV-2. CONTRIBUTION OF INFILTRATION TO WEIGHTED AVERAGE BASELINE RISK

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Appendix A

SUMMARY OF STATE AND FEDERAL REGULATIONS

RELATED TO

ONSHORE OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION

SUMMARY OF STATE AND FEDERAL REGULATIONS

RELATED TO

ONSHORE OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION

NOTICE

THE INFORMATION CONTAINED IN THIS APPENDIX HAS NOT YET BEEN VERIFIED BY STATE AGENCIES. WE INVITE THE COMMENTS OF STATE AGENCIES ON THESE SUMMARIES. SUGGESTIONS AND COMMENTS WILL BE INCLUDED IN THE REPORT TO CONGRESS. PLEASE SUBMIT COMMENTS TO:

Susan L. de Nagy
Industrial Technology Division
U.S. Environmental Protection Agency
401 M Street, S.W.
Washington, DC 20460

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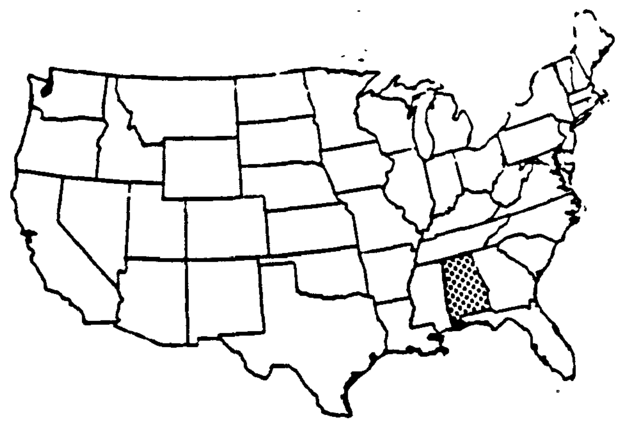
SUMMARY OF STATE REGULATIONS

ALABAMA

INTRODUCTION



Alabama produced 8,438,000 barrels of oil and gas from 760 oil wells and 130 x 10^9 cubic feet of gas from 509 conventional gas wells and 184 coalbed methane wells in 1984. Thirteen percent of conventional oil and gas wells are strippers; 52 percent of coalbed methane wells are strippers.

Alabama began limited regulation of oil and gas activities in 1946. Regulations for disposal of drilling wastes were adopted in 1973. Regulations and/or administrative codes have continued to be revised during the forty years of regulation.

STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activity in Alabama:

- Alabama State Oil and Gas Board
- Alabama Department of Environmental Management
- U.S. Bureau of Land Management
- U.S. Corps of Engineers

The Alabama State Oil and Gas Board is "charged with preventing the waste of Alabama's oil and gas resources and protecting the correlative rights of owners." In carrying out its mandate, the Board issues drilling permits for oil and gas operations through the production phase. The Oil and Gas Board has authority to issue permits for UIC Class II wells. The Oil and Gas Board Administrative Code details statewide rules applicable to all categories. The Administrative Code is supported by Oil and Gas Laws of Alabama (1975).

The Alabama Department of Environmental Management has the authority to issue permits for all UIC wells other than Class II. The Department of Environmental Management also has NPDES authority. The Oil and Gas Board and Department of Environmental Management operate under a 1979 Memorandum of Agreement which requires the Board to forward information regarding actual or proposed discharges to the Department of Environmental Management.

The U.S. Bureau of Land Management authority and regulations for Federally-held mineral rights are discussed separately under Federal Agencies. The U.S. Forest Service retains surface rights (and usually coordinates stipulations with the Bureau of Land Management) in Federal forests and grasslands.

STATE RULES AND REGULATIONS

DRILLING

Drilling pits are permitted by the Oil and Gas Board. The Board has certain construction requirements to ensure the integrity of the pit. Pits are closed by dewatering (see below), then backfilling, leveling, and compacting.

Drilling muds and pit fluids may be disposed in one of three ways. They may be injected into a formation below underground sources of drinking water. They may be transported to a drilling mud treatment (recycling) facility. In non-wetland areas, the fluids may be applied to the land surface or into an approved landfill if:

- The chloride concentration is less than 500 mg/L
- The Oil and Gas Board is properly notified
- The landowner provides written approval
- It is a one-time-only application
- There will be no discharge to surface body of water

These activities are permitted by the Oil and Gas Board prior to allowing disposal of fluids.

PRODUCTION

No discharge of produced water (brine) is allowed. Class II UIC wells are used for disposal of Alabama brines.

After conferring with EPA, EPA-Region IV has advised Alabama authorities that coalbed methane production is not covered under the Federal onshore oil and gas regulations. Produced waters from coalbed methane wells may be allowed to accumulate in lined pits, settle, and then may be discharged directly into live streams.

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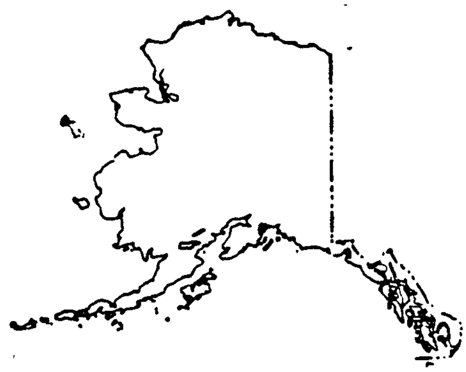
ALASKA

INTRODUCTION



Alaska produced 617,606,000 barrels of oil and 300 x 10^9 cubic feet of gas in 1984. Production is from 864 oil wells and 81 gas wells. Alaska is second in U.S. oil production but twenty-third in the number of producing oil wells. It ranks eighth in U.S. gas production and twenty-fourth in the number of producing gas wells.

Alaska has two main oil and gas development areas: the South Central area and the North Slope area. The South Central area includes Cook Inlet and the Kenai Peninsula. There are 13 oil platforms and one gas platform in Cook Inlet. These wells are considered to be in the Coastal Subcategory.

The Kenai Peninsula produces mostly gas with little associated brine. Brines are primarily reinjected. Drilling muds present a larger problem in the Kenai Peninsula. Three to four hundred wells, mostly onshore, have been drilled. Most of the reserve pits have been unregulated.

The North Slope sends about 1.5 million barrels of oil down the pipeline per day from three producing units (Kuparuk, Prudhoe, and Milne Point). There is a lot of exploration occurring on the North Slope and the exploration is moving east toward the Canadian border.

STATE REGULATORY AGENCIES

Five agencies regulate oil and gas activities in Alaska:

- Alaska Oil and Gas Conservation Commission
- Alaska Department of Environmental Conservation
- U.S. Bureau of Land Management
- U.S. Fish and Wildlife Service
- Alaska Department of Natural Resources

The Oil and Conservation Commission permits wells regarding conservation of resources. It checks well casings to prevent contamination of water and the Commission has primacy for the UIC Class II program. Section 31.05.009 of Title 31 of Alaska Statutes established membership of the Oil and Gas Conservation

Commission to three members appointed by the Governor. There is a compliance bond of $100,000 for an individual well or $200,000 for a blanket bond.

The Alaska Department of Environmental Conservation regulates waste disposal and issues permits regarding waste disposal.

The U.S. Bureau of Land Management is responsible for all oil and gas activity on Federal lands. There are 370 million acres of land in Alaska, of which 250 to 200 million are Federal acres. There are 150 producing oil and gas wells on Federal leases. The BLM works closely with the Alaska Department of Environmental Conservation to regulate these wells. Regulatory processes for oil and gas operations are covered in Onshore Oil and Gas Order No. 1 and Regulation 43 CFR 3160.

The U.S. Fish and Wildlife Service has been conducting research related to the permitted discharge of drilling and production fluids to the tundra wetlands. The research project currently in progress is designed to determine the deleterious nature of the discharge to wildlife in wetlands, especially the waterfowl.

The Department of Natural Resources distributes leases for wells on State land. Stipulations are made to environmental concerns, such as requiring that reserve pits be rendered impermeable or denying the discharge of produced waters to the tundra, at lease award.

STATE RULES AND REGULATIONS

DRILLING

Existing drilling pits and reserve pits are not lined. Many are located in wetlands. The Department of Environmental Conservation is moving toward reducing pit sizes, subgrading pits to enhance freezeback, injecting liquids, and capping pits to prevent ponding. Currently, everything is put in reserve pits including materials from mouse holes, rat holes, sewage, and other wastes. Waste segregation and separate waste treatment with fluid injection is a Department goal.

With pit closure, pits must be dewatered, stabilized to hold the cover, and covered. Fluids often are reinjected down an annulus in a nearby exploratory well.

PRODUCTION

Production fluids have been injected, used on roads, or discharged to the tundra. The department is moving toward reinjecting the fluids, and the use on roads is being considered carefully because of potential pollution problems.

There are two general wastewater disposal permits issued under Alaska Statute 46.03 of the Alaska Administrative Code. These discharges are considered minor discharges by the U.S. Environmental Protection Agency and thus do not require an NPDES permit. The permits are for discharges from onshore reserve pits used for storage of produced water, drilling fluids and cuttings, boiler blowdown, rig washing fluids, and completion fluids.

In 1985, 36 million gallons were discharged from 43 reserve pits. Of the 43 pits, 35 violated permit limits; of the 35, 16 were in violation of the manganese limit only. Manganese was deleted from the 1986 permit because of high levels found naturally in the North Slope. Discharge is to the tundra.

The permit discharge limits are:

pH	6.5 to 8.5
Chemical oxygen demand	200 mg/l
Settleable solids	0.2 mg/l
Oil and grease	15 mg/l
Total aromatic hydrocarbons	10 µg/l
Arsenic	0.05 mg/l
Barium	1.0 mg/l
Cadmium	0.01 mg/l
Chromium	0.05 mg/l
Lead	0.05 mg/l
Mercury	0.002 mg/l

The environmental effects of large-scale reserve pit fluids disposal to the tundra are unknown. Annually, 31 million gallons of the fluids, which originate from drill muds, workover fluids, snow melt, and other sources, must be disposed of from the pits. Alternatives to tundra disposal include dedicated disposal wells on the North Slope. Trucking is usually needed to get the muds to one of the dedicated disposal wells. To avoid trucking associated with injecting down one of the dedicated wells, it is often possible to inject down the annulus of the well being drilled or another well on the pad. The annulus of these wells usually terminates at the bottom of the permafrost layer, about 2,000 feet below the ground surface. These are short-term options, as the annulus must soon be cemented closed to preserve the integrity of the permafrost and prevent collapse of the well. Once cemented closed, it cannot be reopened.

OFFSITE AND COMMERCIAL PITS

Hauling from two or three well sites to another pad has been allowed to concentrate wastes at one site.

Presently, there are no offsite and commercial pits. There was one commercial pit, but it was closed because of pollution problems; the case is in litigation.

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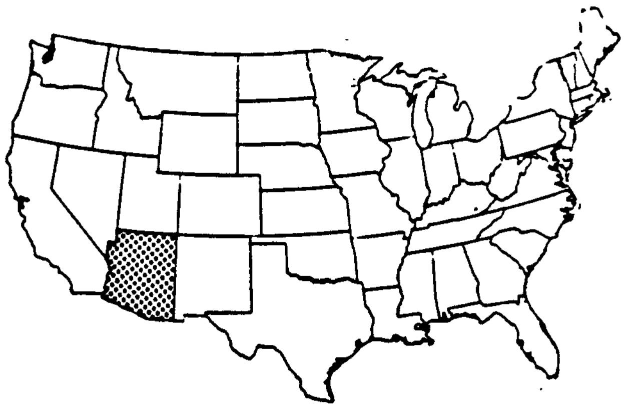
Dan Wilkerson, Alaska Department of Environmental Conservation (907) 274-2533.

Doug Redburn, Chief of Water Quality Management Section, Juneau (907) 465-2666.

ARIZONA

INTRODUCTION



Arizona produced 214,000 barrels of oil and 225 MMCF of gas in 1984. Production was from 26 oil wells and 5 gas wells. All brines are reinjected and all drilling fluids go to reserve pits. Approximately 655 bbls/day of brines are produced in the State per day. Arizona does not have NPDES or UIC program primacy.

REGULATORY AGENCIES

There are five agencies that regulate the oil and gas industry in Arizona:

- U.S. Bureau of Land Management
- U.S. Bureau of Indian Affairs
- Arizona Oil and Gas Commission
- Arizona Department of Health and Safety
- EPA, Region IX

The Bureau of Land Management has the authority to issue oil and gas drilling permits for Federal minerals. Where Indian mineral rights prevail, oil and gas activity may be governed by both the BLM and the Bureau of Indian Affairs.

The Arizona Oil and Gas Commission reviews all oil and gas drilling applications and is primarily responsible for approving and enforcing oil and gas activities. The Oil and Gas Commission's regulations pertain to the construction, location, and operation of onsite drilling and production activities.

The Department of Health and Safety Coordinates with EPA's Region IX for any surface water discharge or underground injection permit. Region IX administers the UIC program; there are no discharges from oil and gas facilities.

STATE RULES AND REGULATIONS

Arizona's Official Compilation of Administrative Rules and Regulations, Chapter 7, Oil and Gas Conservation Commission, states in Section R12-7-140 that, "The owner or operator shall take all reasonable precautions to avoid polluting streams, polluting underground water, and damaging soil." These regulations govern all construction, binding, well spacing, reporting, and abandonment procedures for oil and gas activities. Permit requirements for injection wells are specified, but the substance to be injected is not mentioned. Section R12-7-108 states that, "In order to assure a supply of drilling mud to confine oil, gas or water to its native stratum during the drilling of any well, operators shall provide, before drilling is commenced, an adequate pit, either earthen or portable, for the drilling mud or the accumulation of drill cuttings."

REFERENCES

Ray Brady, Deputy State Director, Division of Mineral Resources. Letter to EPA. September 4, 1985.

Official Compilation of Administrative Rules and Regulations for Arizona, Chapter 7, Oil and Gas Conservation Commission, Article 1. Oil, Gas and Helium. 1975.

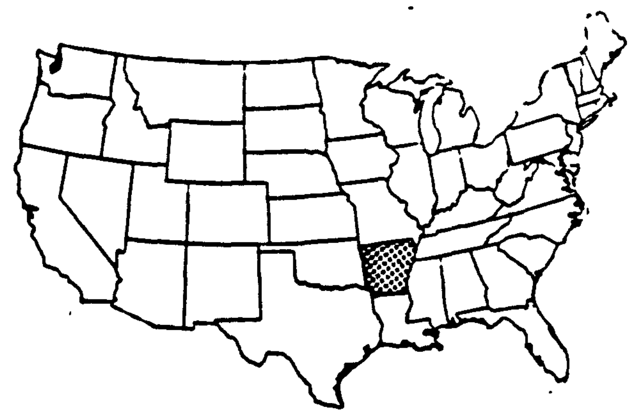
Personal Communications:

Lyndon Hammon, NPDES Permits Section Manager, Arizona Department of Health and Safety. September 29, 1986 (602) 257-2262.

Nate Lau, Director of the UIC Division, EPA Region IX. September 28, 1986 (415) 974-0893.

ARKANSAS

INTRODUCTION



Arkansas produces 17,618,000 barrels of oil and 162,678 MM cubic feet of gas each year. Production is from 9,490 oil wells and 2,492 gas wells. The State is divided into two geographical districts. The Arcoma Basin, located in the northwest corner of the State, produces 99 percent natural gas on a volume basis. The Mississippi Embayment in southeastern Arkansas produces approximately 90 percent oil and 10 percent gas.

STATE REGULATORY AGENCIES

Two agencies regulate oil and gas activity in Arkansas:

- Arkansas Oil and Gas Commission
- Arkansas Department of Pollution Control and Ecology

The Arkansas Oil and Gas Commission, a division of the Arkansas Department of Commerce, regulates industry practices regarding drilling and production of oil and gas wells by means of Statewide General Rules and Regulations Order No. 2-39. The General Rules and Regulations do not address all aspects of industry practices, and refer the reader to "special rules pertaining to individual oil, gas, or salt water fields and pools." Special rules of any non-emergency nature require a public hearing, and are provided for in Rules A-2 and B-38 of the General Rules and Regulations. The reader of this document is also advised that, "There is a considerable body of statutory law in Arkansas that must be consulted in evaluating an oil and gas matter," and is referred to the Arkansas Statutes, Annotated, Title 53.

The Arkansas Department of Pollution Control and Ecology, a division of the Water Pollution Control Commission, derives its regulatory authority from Regulation No. 1, "Regulation for the prevention of pollution by salt water and other oil field wastes produced by wells in new fields or pools." The regulation was promulgated on October 13, 1958, pursuant to the authority provided by Act 472 of the Acts of Arkansas for 1949, and is currently being revised. The updated regulation is being modeled after Louisiana State Order No. 29-B, and is expected to be promulgated in 1987.

It is apparent from the regulations that there are areas in which the responsibilities of these two agencies overlap. "Memorandums of Understanding" are on file that define the role of each agency as it applies to oil and gas regulations. For example, the Arkansas Oil and Gas Commission regulates underground disposal of salt water, and the Arkansas Department of Pollution Control regulates surface discharges of salt water. The state does not have NPDES delegated authority.

STATE RULES AND REGULATIONS

DRILLING

Section 4 of Regulation No. 1 forbids discharging salt water from an oil or gas well such that the salt water may come in contact with "any of the waters of the State, whether by natural drainage, seepage, overflow, or otherwise." Other sections of Regulation No. 1 require the well operator to obtain a permit for a waste disposal system that prevents the wastes from contacting State waters. The regulation provides two alternatives for salt water disposal: subsurface discharge in disposal wells constructed in accordance with the Rules and Regulations of the Arkansas Oil and Gas Commission, and surface discharge into lined earthen pits.

The Arkansas Department of Pollution Control and Ecology issues a letter of authorization that serves as an informal permit for the construction of reserve pits on drill sites. The Department uses the letter to clarify and add strength to the outdated Regulation No. 1 which is currently being revised. The letter lists conditions which the Department of Pollution Control and Ecology expects to be followed during drilling operations pertaining to reserve pit construction, pit fluid and drilling mud disposal, and drill site reclamation.

All earthen pits must be lined with a synthetic liner (20 mils thick) or a clay liner (18 to 24 inches thick), and must maintain at least 2 feet of freeboard. Pits must be reclaimed to grade and seeded within 60 days after the drilling rig has been removed from the site.

Reserve pit wastes may be treated and land applied at the drill site if they contain less than 2,000 mg/l total dissolved solids, and if they are treated. Wastes having greater than 2,000 mg/l TDS must be disposed of in State-permitted disposal wells.

The letter of authorization also states that completion fluids high in total dissolved solids, such as KCl, should be kept separate from the contents of the reserve pit, and recommends that a lined pit be used for this purpose.

Disposal of reserve pit fluids and drilling mud requires a permit from the Arkansas Department of Pollution Control and Ecology. The permit requires that the disposal company provide an analysis of the pit fluids and drilling mud, the amount hauled, and its final destination. A disposal company that is permitted to land apply pit fluid and drilling mud near the well must provide the Department with a copy of the land owner's agreement as well as an analysis of the wastes. An analysis of pit fluid will include tests for chlorides and pH, and a drilling mud analysis will include tests for chromium, zinc, chlorides, and pH.

PRODUCTION

Rule C-7 of the General Rules and Regulations defines the means by which salt water produced from oil and gas wells may be discharged into subsurface formations. The Oil and Gas Commission states that it will consult the State Geological Survey and the State Board of Health, when reviewing an application to inject salt water, in order to protect fresh water supplies. Disposal wells are to be cased and cemented "in such manner that damage will not be caused to oil, gas or fresh water resources." The mechanical integrity of a disposal well is to be tested prior to its first use, and at least once every 5 years thereafter. A monthly salt water disposal report is required that includes the amount of water injected, the injection pressure, and the zone into which the salt water is injected.

The letter of authorization issued by the Arkansas Department of Pollution Control and Ecology states that salt water produced any time during the lifetime of a well will remain the responsibility of the production company, and "shall be stored in a plastic or fiberglass tank above ground and resting on a concrete pad."

OFFSITE AND COMMERCIAL PITS

State regulations do not address offsite and commercial pits.

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Arkansas Department of Pollution Control and Ecology, "Regulation No. 1," October, 1958.

Arkansas Oil and Gas Commission, "State of Arkansas Rules and Regulations Order No. 2-39," revised 1983.

Interstate Oil Compact Commission, The Oil and Gas Compact Bulletin, Volume XLIV, No. 2, December 1985.

Interstate Oil Compact Commission, Summary of State Statutes and Regulations for Oil and Gas Production, June 1986.

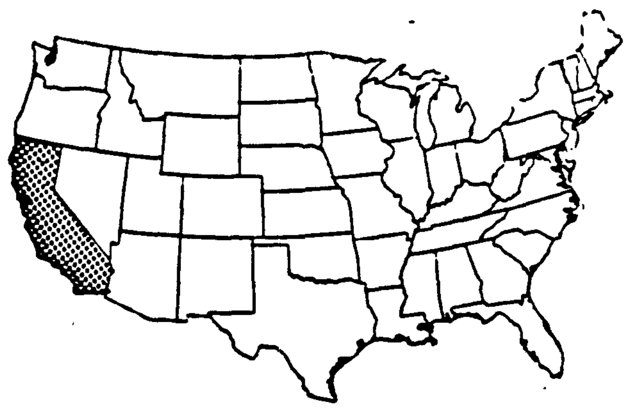
U.S. Environmental Protection Agency, Proceedings: Onshore Oil and Gas State/Federal Western Workshop, December 1985.

Letter of Authorization from Mr. David A. Thomas, Arkansas Department of Pollution Control and Ecology, to Mr. William S. Walker, Stevens Production Company, August 20, 1986.

Letter to Mr. Naresh R. Shah, West Virginia Department of Natural Resources Permits Branch, from Mr. Terry Muse, Arkansas Department of Pollution Control and Ecology, regarding Arkansas Water Permit No. 2839-W, March 2, 1984.

CALIFORNIA

INTRODUCTION



California produced 411,665,000 barrels of oil and 470 x 10^9 cubic feet of gas in 1984. California ranked fourth in U.S. oil production and sixth in U.S. gas production. Production is from 48,908 producing oil wells and 1,220 producing gas wells. Approximately 55 percent of the oil production is attributed to enhanced oil recovery.

At present, California has 10,652 Class II wells: 9,657 are injecting fluids back into hydrocarbon producing zones; 971 are water disposal wells. Some of the water produced in association with oil and gas in the San Joaquin Valley is of a good quality. In those cases, the water is cleaned up through filtration and used for irrigation purposes. Some waters produced in urban oil fields are disposed into municipal sewer systems.

California has been injecting fluids into non-hydrocarbon-producing zones of the Santa Maria Valley and the Salinas Valley for many years. Fluids from shallow, heavy oil steam flood production is injected into other formations such as the Santa Margarita.

STATE REGULATORY AGENCIES

Eight agencies regulate oil and gas activity in California:

- California Department of Conservation, Division of Oil and Gas
- California Water Resources Control Board with the program administered through nine Regional Water Quality Control Boards
- State Lands Commission
- State Air Pollution Control Districts
- California Department of Fish and Game
- Local governmental agencies
- U.S. Bureau of Land Management
- U.S. Department of Energy

The California Division of Oil and Gas was created in 1915 by the State legislature. The Division was given the authority to supervise the drilling, operation, maintenance, and abandonment of oil and gas wells to prevent, as far as possible, damage to oil and gas deposits from infiltering water and other causes and to prevent loss of oil and gas reservoir energy.

Since 1915, operators have been required to obtain a permit prior to drilling, reworking, or abandoning a well. At the time of permit application, engineers have prescribed well casing, cementing, testing, and/or plugging requirements. In the early 1930s, additional legislation was passed that provided well spacing and well bonding statutes. At that time, the State Oil and Gas Supervisor was mandated to prevent damage to underground and surface waters suitable for irrigation or domestic purposes from degradation from oil and gas operations. The Division has been delegated authority to issue UIC permits for Class II wells.

The Water Quality Control Boards have statutory responsibility to protect waters of the State and to preserve all present and anticipated beneficial uses of those waters. The Water Resources Control Board has been delegated authority to issue NPDES permits. The Division of Oil and Gas and the Water Quality Control Boards have entered into a Memorandum of Understanding to provide a coordinated approach resulting in a single permit that satisfies the responsibilities of each agency. Basically, the coordinated approach uses a method that provides the other agency with the opportunity to comment on the proposed waste discharge requirements. A permit to discharge will not be issued unless the concerns of each agency are satisfied.

For wells on State-owned, onshore lands, the State Lands Commission has joint responsibilities with the Division of Oil and Gas. Their responsibilities are expressed in the provisions of the lease terms.

State Air Pollution Control Districts issue permits to operate equipment that emits pollutants into the atmosphere. The equipment includes steam generators used for enhanced oil recovery projects.

The California Department of Fish and Game provides comments and recommendations on methods to mitigate any problems that oil and gas operations may have on fish and wildlife. They coordinate State operations involving any spills that affect fish and wildlife.

Cities and counties also issue land use permits for oil and gas operations. Generally, a condition of their permit requires that an operator comply with the Division of Oil and Gas regulations.

The Bureau of Land Management approves approximately 400 oil and gas drilling permits per year on Federal lands. BLM has approximately 350 water disposal wells and approximately 500 earthen sumps for water disposal. Presently, there are 6,200 oil, gas, and injection wells on Federal lands. The oil and gas wells produce approximately 22-1/4 million barrels of water per month. Most of this water is reused in steam flooding projects, some goes into evaporation ponds, and some is reinjected for water flooding projects. Presently, the BLM and Division of Oil and Gas are negotiating a Memorandum of Understanding under the UIC program on Federal wells.

The Department of Energy manages the Elk Hills Naval Petroleum Reserves. These fields produce approximately 80,000 barrels of water per day, 133,000 barrels of oil per day, and 390 billion cubic feet of gas per day, from 1,900 wells. There are 13 injection wells and, during fiscal year 1985, 23 new wells were drilled. For fiscal year 1986, 36 new wells are planned. The Department of Energy's goal will be to stop the disposal of produced water in sumps by the end of fiscal year 1986. Presently, 1,400 barrels per day ar disposed into 34 earthen sumps.

STATE RULES AND REGULATIONS

Drilling muds are disposed at State-approved hazardous waste disposal sites if the muds contain constituents considered to be hazardous. Nonhazardous muds can be left in a drilling waste pit if the free liquid is removed and the solids and semisolids are nonhazardous. The drilling pit is reclaimed at the end of the drilling operation.

Drilling pits may or may not need to be lined or sealed depending upon their location. The State agency doesn't prescribe pit construction conditions. The conditional use permit that a driller obtains from each county generally details the pit requirements. If the fluids contain hazardous materials, the pits would have to have liners. At the completion of a well, drilling fluids may be transported offsite generally to evaporation sumps.

On Federal lands, drilling fluids are left in the sump until completion of the well. After completion of the well, drilling fluids are hauled to a Class II disposal site for oil field wastes. Most of these sites are surface sumps.

Usually there is one pit for each drilled well but often portable tanks are used in lieu of sumps. Mud pits usually are in existence until the time of well completion or abandonment in the case of dry holes. Brine pits are located only in areas where percolation is allowed and they remain in existence as long as needed. Emergency pits are allowed as long as they are evacuated and cleaned after any spill.

PRODUCTION

Production waters are disposed approximately as follows:

Evaporation in percolation sumps	-	18 percent
Evaporation in lined sumps	-	6 percent
To sewer systems	-	2 percent
To surface water	-	18 percent
Underground injection	-	56 percent

The small percentage that goes to sewer systems predominantly is within the Los Angeles County Sanitation District. Production waters entering such sewers must meet applicable pretreatment standards including a maximum oil and grease content of 75 mg/l, heavy metals limits, cyanide, chlorinated hydrocarbons, and sulfides. There is no pretreatment limit for chloride.

Some production waters are permitted for discharge to waters of the United States including principally irrigation canals, ephemeral streams, and dry ditches. There are at least 12 such permits in the Fresno office of the Regional Water Quality Board. There are a number of additional such discharges that currently are pending a determination by the U.S. Environmental Protection Agency. Discharge permit limits include the following maximum values:

Electrical conductivity	1,000 μ mhos
Boron	1 mg/l
Chlorides	200 mg/l
Oil and grease	35 mg/l

OFFSITE AND COMMERCIAL PITS

On the western side of the San Joaquin Valley, there is a wastewater disposal facility permitted on Federal land where the oil industry has gotten together with a private consultant and permitted a series of sumps that cover approximately 20 to 40 acres. These sumps are used for percolation and evaporation. BLM has some sumps on Federal leases that range up to roughly 5 acres. The quality of groundwater on the west side is very poor.

Drilling fluids and production brines may be transported to offsite and commercial pits. Drilling fluids generally are received by evaporation sumps, but many such sumps are used for percolation and evaporation where fresh water sources are not nearby. A manifest is not required unless the material transported is a hazardous waste.

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Personal Communications:

Bob Reid, Division of Oil and Gas (916) 445-9686.

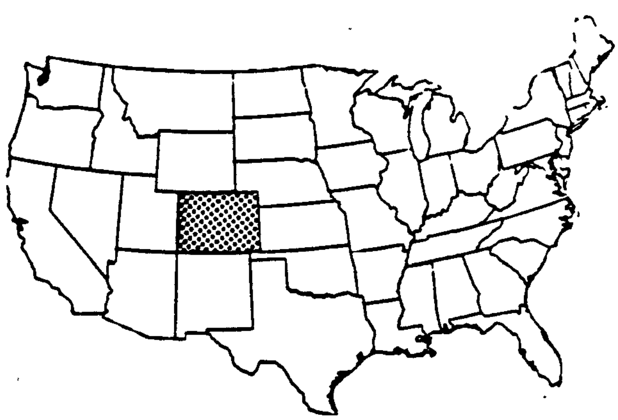
Scott Smith, Central Valley Water Quality Board (209) 445-5116.

Chong Rhee, L.A. County Sanitation District (213) 699-7411.

COLORADO

INTRODUCTION

Colorado has a long history of regulating oil and gas activities. As far back as 1889, Colorado passed a bill prohibiting the discharge of oil, petroleum, or other substances into any waters of the State. In 1950, a second bill was passed that included provisions for well plugging. In 1951, the Oil and Gas Conservation Act was passed. The Solid Wastes Disposal Sites and Facilities Act (Title 30-20-Part 1, C.R.S. 1973, as amended) also has jurisdiction.



In 1985, Colorado produced 38,584,000 barrels of oil from 5,287 wells; 271,544 million cubic feet of gas were produced from 4,665 gas wells. Mud and air drilling are both encountered.

STATE REGULATORY AGENCIES

Three agencies share regulatory authority for oil and gas wastes in Colorado:

- Department of Natural Resources-Oil and Gas Conservation Commission
- Department of Health
- U.S. Bureau of Land Management

The Colorado Department of Natural Resources and Department of Health share statutory and regulatory authority over oil and gas activities in the State. Two divisions of the Department of Health--the Water Quality Control Division/Commission and the Waste Management Division--have statutory and regulatory authority over solid waste disposal sites and facilities (discharges and evaporation ponds, respectively). The Oil and Gas Conservation Commission is dedicated to prevention of wastes and conservation of oil and gas; the Department of Health is concerned with endangerment of public health or the environment.

The shared regulatory responsibilities between the Oil and Gas Conservation Commission and the Department of Health were worked out in a 1971 Memorandum of Agreement between the groups. In this agreement, primary responsibility for oil and gas activities were delegated to the Oil and Gas Conservation Commission. The

Department of Health retained the responsibility for offsite disposal of oil and gas wastes. The Department of Health has since sought to update the Memorandum, but the Oil and Gas Conservation Commission has declined to change the agreement. In fact, the Oil and Gas Conservation Commission has recommended that their authority be expanded to cover offsite pits, ponds, and lagoons (currently regulated by the Department of Health).

The Colorado Department of Natural Resources, Oil and Gas Conservation Commission amended its rules and regulations effective July 16, 1984.

The U.S. Bureau of Land Management has jurisdiction over Federally-owned mineral rights. The U.S. Forest Service retains surface rights on Federally-owned forests and grasslands. Both agencies are discussed separately under Federal Agencies.

STATE RULES AND REGULATIONS

DRILLING

Oil and Gas Conservation Commission rules provide that, "Before commencing to drill, proper and adequate slush pits shall be constructed for the reception of mud and cutting and to facilitate the drilling operation. Special precautions shall be taken to prevent contamination or pollution of state waters." Rule 324 charges owners with the responsibility to take "such precautions as necessary to prevent polluting the waters of the state . . . by oilfield wastes." The rule does not contain specific guidance regarding achievement of this goal.

Section 325 of the 1984 Rules and Regulations sets forth the requirements for disposal of water produced with oil and gas operations or other oil field waste into retaining pits. The Oil and Gas Conservation Commission requires demonstration (via geological information, percolation tests, or other means) that the proposed retention pond will not pollute surface or groundwater. The rule also requires chemical analysis of the wastes to be stored and of the domestic water supply nearby. No provisions for pit closure are noted in the Commission's Rules and Regulations.

The Oil and Gas Conservation Commission rules and regulations for drilling coincide with Department of Health Rules and Regulations, which are applicable for all waste impoundments. The Department of Health regulations set forth site standards (including engineering design, geologic, operational, hydrologic, and other data) for all facilities. For impoundments of oil and gas wastes, the Department of Health considers facilities in compliance if they are regulated by the Oil and Gas Conservation Commission or if there is no endangerment of public health or the environment.

The Department of Health regulations also set standards for closure of facilities. These standards include provisions for testing of remaining sludge for hazardous characteristics and final disposal of the sludge. The provisions are not reflected in Oil and Gas Conservation Commission rules.

The Oil and Gas Conservation Commission rules have extensive notification and construction requirements (including spacing requirements) for wells.

The Oil and Gas Conservation Commission requires lined pits for 5,000 mg/l total dissolved solids waters. Reserve pit sludge is dried out and disposed of on the surface by tilling it into the ground. The sludge may be moved to a different location before landfarming. The Oil and Gas Conservation Commission does not consider this practice land application discharge of drilling fluids. The Commission has permitted one facility for land application discharge of wastes with limitations on total suspended solids, total dissolved solids, oil and grease, and chemical oxygen demand.

PRODUCTION

Oil and Gas Conservation Commission rules and regulations do not distinguish between handling of produced waters and handling other drilling or oil field wastes.

Produced water often is discharged under the provisions of the BPT Wildlife and Agricultural Use Subcategory. In some cases, the well operator has been asked by the landowner to put an accumulation sump and head gate in to allow build up of produced waters before being used for watering cattle.

COMMERCIAL BRINE DISPOSAL FACILITIES

The Department of Health permits 10 to 15 commercial brine disposal facilities to discharge under the BPT Wildlife and Agricultural Use Subcategory. These discharges must generally meet the following limitations:

- $6.0 \geq pH \leq 9.0$
- Total suspended solids of 30 mg/l 30-day average (45 maximum one-day)
- Oil and grease less than 10 mg/l
- Total dissolved solids of 5000 mg/l 30-day average (7500 mg/l maximum one-day)
- Some metals are limited by Water Quality Standards

Flows from these facilities are on the order of 10,000 gallons per day.

Centralized pits are used for long term disposal in Colorado.

REFERENCES

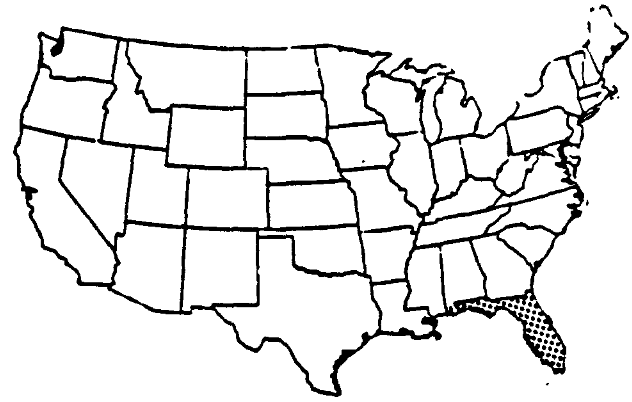
Interstate Oil Compact Commission, The Oil and Gas Compact Bulletin, Volume XLIV, No. 2, December 1985.

U.S. EPA, Proceedings of the Onshore Oil and Gas State/Federal Western Workshop, December 1985.

Colorado Department of Health. Statement of the Colorado Department of Health for the Informational Hearing Regarding Oil and Gas Brine Waste Disposal to the Colorado Water Quality Control Commission. May 10, 1983.

State of Colorado. Department of Natural Resources. Oil and Gas Conservation Commission. Rules and Regulations, Rules of Practice and Procedure, and Oil and Gas Conservation Act (As Amended). Effective July 16, 1984.

State of Colorado. Regulations Pertaining to Solid Waste Disposal Sites and Facilities, Effective Date: October 1, 1984.



INTRODUCTION

Florida produced 14,090,000 barrels of oil and 15 x 10^9 cubic feet of gas in 1984. Production was from 165 oil wells; there are no producing gas wells. Virtually all drilling fluids as well as produced fluids are reinjected.

STATE REGULATORY PROGRAMS

Three agencies are primarily responsible for regulating the oil and gas industry in Florida:

- Florida Department of Natural Resources, Division of Resources Management, Bureau of Biology
- Florida Department of Environmental Regulation
- Florida Regional Water Management Districts
- U.S. Environmental Protection Agency, Region IV

The Department of Natural Resources (DNR) is the permitting agency for oil and gas wells, including approval to dispose of waste fluids by subsurface injection. The DNR regulates the exploration, drilling, and production of the oil and gas industry with respect to reporting, spacing, safety, and construction.

The Department of Environmental Regulation oversees the industry with respect to water quality standards and dredge and fill requirements (for pits) if oil and gas activities occur in waters of the State.

Florida's Regional Water Management Districts, which are separate regulatory groups on a local level, regulate oil and gas activities with regard to water use. Consumptive use permits are issued if applicable.

Other State agencies may be involved on a case-by-case basis. These agencies are the Florida Game and Freshwater Fish Commission, the Department of Community Affairs, and the Department of Transportation.

The State of Florida does not have primacy for Class II UIC program wells. The State operates a separate program for injection wells with a State permit and State inspections. A driller wishing to inject fluids underground must apply for permit to do so from two separate governmental entities, the U.S. Environmental Protection Agency Region IV and the State, and undergo two sets of inspections.

STATE RULES AND REGULATIONS

Drilling fluids are put into pits during operation but then disposed of by reinjection. Pits are nearly dry when they are backfilled. All produced waters are reinjected.

The DNR is governed by Chapter 377, Florida Statutes, and its implementing rules, Chapters 16C-25 through 16C-30, Florida Administrative Code. Part of Chapter 377's specific purpose is to "require the drilling, casing, and plugging of wells to be done in such a manner as to prevent the pollution of fresh, salt, or brackish waters on the lands of the State." And Section 377.371 further states that, "No person drilling for or producing oil, gas, or other petroleum products shall pollute land or water; damage aquatic or marine life, wildlife, birds, or public or private property."

UIC permits are issued pursuant to Chapter 403, Florida Statutes and Chapter 17-28, Florida Administrative Code. If applicable, dredge and fill activities are regulated under Chapter 403, Florida Statutes, Chapter 17-12 Florida Administrative Code, and water standards are issued under Chapters 17-3 and 17-4, Florida Administrative Code. Water management licenses (consumptive use) are issued under Chapter 373, Florida Statutes, by the regional Water Management Districts.

REFERENCES

Lloyd Wise, Region IV NPDES permit writer, Summary of EPA Workshop presentation, Onshore Oil and Gas Workshop Meeting Report. July 1985.

Lynn Griffin, Environmental Specialist, Department of Environmental Regulation. Letter to W. A. Telliard, EPA, March 22, 1985.

State of Florida Regulatory and Review Procedures for Land Development. Chapter 14. November 1, 1984.

Personal Communication:

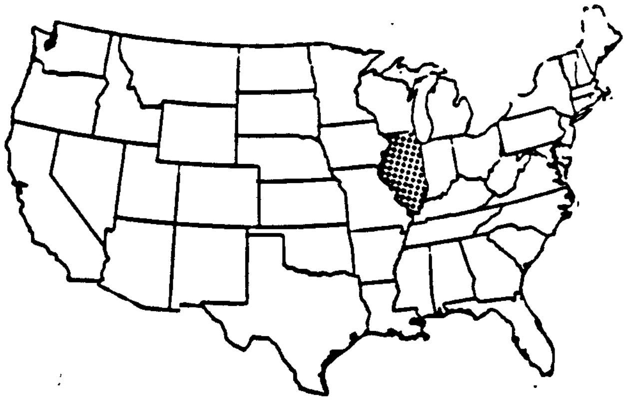
Lynn Griffin, Environmental Specialist, Department of Environmental Regulation, October 2, 1986 (904) 488-8615.

David Curry, Florida Department of Natural Resources (904) 487-2219.

ILLINOIS

INTRODUCTION

Illinois produced 28,873,000 barrels of oil and 15 x 10^9 cubic feet of gas in 1984. Production is from 28,920 oil wells and 157 gas wells. Nineteen barrels of brine are produced for every barrel of oil. Twelve thousand injection wells are operating in the State.



STATE REGULATORY AGENCY

Principally one agency regulates the oil and gas industry in Illinois:

- Department of Mines and Minerals, Division of Oil and Gas

The Department of Mines and Minerals operates under an Act in Relation to Oil, Gas, Coal and Other Surface and Underground Resources. Section 8A of the Act provides the Department with the power and authority to regulate the disposal of salt- or sulphur-bearing water and any oil field waste produced in the operation of any oil or gas well, and to adopt proper rules and regulations relative thereto. Section 8B provides that no person shall drill, convert or deepen a well for the purpose of injecting gas, air, water, or other liquid into any underground formation or strata without first securing a permit therefor. Section 8C(A) states that no person shall operate an oil field brine transportation system without an oil field brine transportation permit. Section 8G(3) specifies that the permittee shall not dispose of oil field brine onto or into the ground except at locations specifically approved and permitted by the Mining Board. No oil field brine shall be placed in a location where it could enter any public or private drain, pond, stream or other body of surface or ground water.

The Division of Oil and Gas has UIC program primary for Class II wells. There are Federal lands in Illinois but there is no drilling or production on Federal lands currently. The Illinois Environmental Protection Agency has been delegated NPDES authority but no surface water discharges from the oil and gas industry are allowed.

STATE RULES AND REGULATIONS

DRILLING

There are no State requirements that drilling pits be permitted or lined. Fluids from the pits may be disposed in a dry drill hole. When the pit mud dries, the pit is back-filled and reclaimed. Pits must be reclaimed within 6 months after drilling ceases.

PRODUCTION

Production fluids go to lined holding-evaporation ponds or they are reinjected into certified injection wells. The lining may be clay or plastic, but recently no requests for plastic-lined pits have been received. Requests now are for fiber glass or concrete lined pits. Earthen lined pits have been substantially eliminated during the past 5 years. The Department of Mines and Minerals has been reducing the number of old pits by removing and injecting the brines, stabilizing the contents, applying topsoil, and vegetating the pit area.

Neither road spreading nor land farming is allowed.

OFFSITE AND COMMERCIAL PITS

Use is not made of offsite or commercial pits in the State of Illinois.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Illinois Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workshop. U.S. Environmental Protection Agency, Washington, D.C. (March 26-27 in Atlanta, GA).

State of Illinois. 1984. An Act in Relation to Oil, Gas, Coal and Other Surface and Underground Resources. Revised Edition.

State of Illinois. 1984. Rules and Regulations. Department of Mines and Minerals, Division of Oil and Gas. Revised Edition.

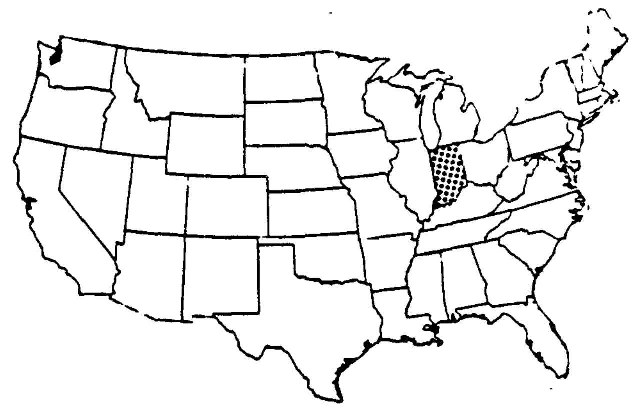
Personal Communication:

George R. Lane, Division of Oil and Gas (217) 782-7756.

INDIANA

INTRODUCTION

Indiana produced 5,394,000 barrels of oil and 394,000,000 cubic feet of gas in 1984. Production was from 6,792 oil wells and 2,294 gas wells.



STATE REGULATORY AGENCIES

Two agencies principally regulate oil and gas activity in Indiana:

- Indiana Division of Oil and Gas
- U.S. Environmental Protection Agency, Region V

The Indiana Division of Oil and Gas regulates the industry through Rule 310 IAC 7-1. No discharge to surface waters is allowed so that any involvement of the Indiana Department of Environmental Management would occur as a result of improper disposal of oil and gas wastes. Concerns that owners of Federal lands may have regarding oil and gas surface treatment are satisfied thorough conditions of the respective lease agreements.

The Oil and Gas Division does not have primacy for UIC program Class II wells. The State is in the process of attaining such status. Currently, however, anyone interested in underground injection must obtain two permits--one from the State, and one from the U.S. Environmental Protection Agency.

STATE RULES AND REGULATIONS

DRILLING

Pits associated with drilling operations are allowed; they are small with a 250 cubic foot capacity, approximately. Drill pits must be reclaimed within 60 days after drilling has stopped. Fluids associated with such drill pits generally can be classified as fresh-water and are mixed with bentonite clays. When a pit is closed, the practice is to pump the small amount of fluid in the pit to the surrounding land, bury the drill cuttings and other pit muds, and reclaim the land.

PRODUCTION

Pits used for gathering production fluids and storing them until reinjection must be lined with impervious clay or an artificial liner. All production fluids must be reinjected underground. Evaporation pits were disallowed by the State two years ago.

OFFSITE AND COMMERCIAL PITS

There is one operating commercial injection well with associated holding pits. Some use is made by a producer at one well of another's holding pits and injection well for produced fluids disposal.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

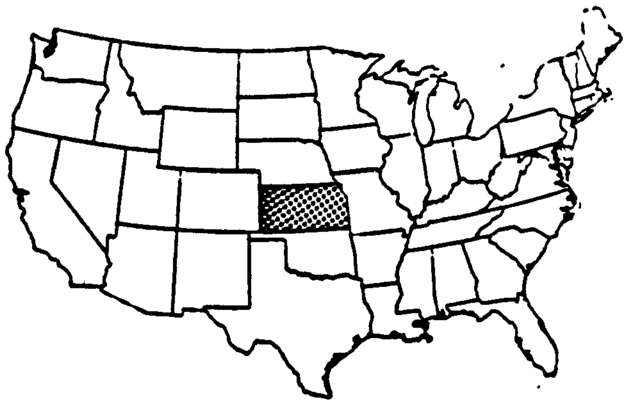
Personal Communication:

Mike Nickolaus, Indiana Division of Oil and Gas (317) 232-4055.

KANSAS

INTRODUCTION

Kansas produced 75,723,000 barrels of oil and 466.6 x 10^9 cubic feet of gas in 1984. Production is from 57,633 producing oil wells and 12,680 gas wells. Kansas ranks seventh in both U.S. oil production and U.S. gas production. There are 11,000 injection wells in the State.



Oil was found in Kansas in the 1860s, but it was not commercially developed until 1895. Oil and gas regulation began in 1935.

STATE REGULATORY AGENCIES

One agency regulates oil and gas activities in Kansas:

- Kansas Corporation Commission

One July 1, 1986, by passage of House Bill 3078, the Kansas Legislature transferred the Department of Health and Environment responsibilities in oil and gas activities regulation to the Kansas Corporation Commission. Prior to July 1, 1986, the Department of Health and Environment maintained certain responsibilities related to lease maintenance, emergency pits, drill pits, burn pits, and storage ponds. Kansas Statute Chapter 55, Article 10, 55-1003 provided that for the disposal of oil and gas brines and mineralized waters, the plans and specifications for such were to be submitted to and approved by the State Corporation Commission and the Secretary of Health and Environment. By legislative action, the Secretary of Health and Environment no longer is a party to such action.

There are few Federal lands and little involvement of Indian Tribes in the Kansas oil and gas industry. The State informs neither party directly when an application for a permit to drill has been received. Such information is published as a routine matter in local news outlets, and if there are specified requirements by the Bureau of Land Management or Indian Tribes, they are communicated directly to the driller through lease agreement condition or by other legal means.

STATE RULES AND REGULATIONS

DRILLING

Kansas Statute 55-156 states that prior to abandonment of any well which has been drilled, is being drilled, or may hereafter by drilled, the operator shall protect usable groundwater or surface water from pollution and from loss through downward drainage by plugging the well, in accordance with the rules and regulations adopted by the Commission. Failure to comply with these rules and regulations shall be a class E felony.

A compliance or surety bond is not required. Regulation of the industry is through the issuance of drilling and well operation permits. With the recent departmental transfer of responsibilities, the Corporation Commission is in the process of resolving issues, revising, and proposing regulations pertaining to those activities formerly administered by the Secretary of Health and Environment.

Drilling pits and burn pits have been regulated under a general permit for a maximum period of 365 days unless the operator requests and receives approval for an extension. No application for permit is required. In the sandy soils of the State, such pits would need to be lined. In the heavy clay region of the North-Central portion, for example, such pits most likely would not be lined.

Permits are required for emergency pits but not reserve pits. If an emergency or reserve pit gets brine in it, it must be pumped out upon termination of the emergency or completion of the well. Kansas does not support transporting contents of reserve pits upon closure to landfills in central locations. Burial on site is the primary method used. There is no law requiring backfilling of pits, but most of the lease agreements contain that provision. In geologically sensitive or hydrogeologically sensitive areas, seals in drilling pits can be required and in situ disposal of drilling pit contents can be prohibited.

PRODUCTION

Kansas Statute 55-901 provides that the owner or operator of any oil or gas well which may be producing and which produces salt water or waters containing minerals in an appreciable degree shall have the right to return said waters to any horizon from which such salt waters may have been produced, or to any other horizon which contains or had previously produced salt water or waters containing minerals in an appreciable degree, if the owner or operator of such well makes a written application to the State Corporation Commission for authority to do so and written approval has been granted him or her after investigation by the State Corporation Commission. Salt water is defined as water with greater than 5,000 mg/l chlorides. Spreading of salt water on roads under construction is not prohibited if approval is received from the Commission. The Commission has primacy for UIC Class II wells.

Requests for a surface pond permit are granted unless denied by the Commission within 10 days. According to proposed Rule 82-3-600, the Commission, in approving applications for surface pond permits, shall consider the protection of soil and water resources from pollution. Each operator of a surface pond shall install observation trenches, holes, or wells if required by the Commission, and seal the pond with artificial material if the Commission determines that an unsealed condition will present a pollution threat to soil or water resources. Surface drainage is to be prevented from entering the pond. During the past two years, it has become a practice, on a case-by-case basis, to require monitoring wells in association with surface ponds.

There are approximately 25 permanent pits, receiving a total of 30 barrels of brine a day, mostly in the Southeast corner of the State where there are no groundwater or seepage problems and where chloride is quite low. Surface discharges of produced brine are not allowed nor is pit disposal allowed.

Upon the permanent cessation of the flow of fluids into any surface pond, all fluids resulting from oil and gas activities shall be removed to a disposal well approved by the Commission, or used for road maintenance or construction if approved by the Commission. Pond solids may be transported to a permitted solid waste landfill or to an approved offsite disposal area; however, this latter condition of former Rule 28-41-5 and currently proposed Rule 82-3-603 has not been used.

OFFSITE AND COMMERCIAL PITS

Use is not made of offsite or commercial pits.

REFERENCES

Kansas Meeting Report. 1985. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. U.S. Environmental Protection Agency, Washington, D.C. (December 1985).

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

General Rules and Regulations, the State Corporation Commission of the State of Kansas (Effective May 1, 1986).

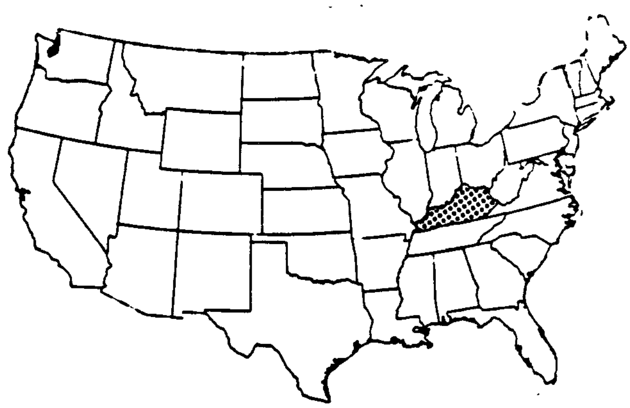
Personal Communication:

Jim Schoff, Kansas Corporation Commission (316) 263-3238.

KENTUCKY

INTRODUCTION

Kentucky produced 7,788,000 barrels of oil from 19,980 oil wells and 61.5 x 10^9 cubic feet of gas from 9,013 gas wells in 1984.



STATE REGULATORY AGENCIES

Five agencies regulate oil and gas activity in Kentucky:

- Kentucky Division of Oil and Gas
- Kentucky Department of Natural Resources and Environmental Protection
- U.S. Bureau of Land Management
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency, Region IV

The Kentucky Division of Oil and Gas issues drill permits and provides well casing and well plugging requirements. The State is seeking primacy but does not yet have primacy for the UIC Class II well program.

The Kentucky Department of Natural Resources and Environmental Protection has NPDES-delegated authority. The Department issues permits for holding pits containing production fluids and instructions, pursuant to regulations, for pit construction.

The U.S. Army Corps of Engineers becomes involved in oil and gas activities on lands maintained for water management projects.

The U.S. Environmental Protection Agency, Region IV, issues UIC program Class II injection well permits.

STATE RULES AND REGULATIONS

DRILLING

Pursuant to Kentucky regulation 401 KAR 5:090, there can be no discharge from a pit without an NPDES permit. Pits used to contain drilling muds or fluids associated with drilling activities do not have to have a permit for construction or operation provided that the pit life is not longer than 30 days. Where the pit life is longer than 30 days, a pit is defined as a holding pit and a permit is required. When a pit no longer is in service, it must be backfilled and the land restored. There are no liner requirements for a pit with less than a 30-day life.

PRODUCTION

A holding pit with a life longer than 30 days must have a permit and must be lined with a synthetic material of 20 mil minimum thickness. The State may grant an exemption to the lining clause for pits that pre-existed the date of regulatory enactment. Construction requirements include at least 1 foot of freeboard and a 2-foot berm above ground around the pit. Surface waters must be diverted from the pit.

No NPDES permits have been issued for discharges from holding pits. However, the Department of Natural Resources and Environmental Protection recently was sued and entered into a consent decree which specified a water quality criterion of 600 mg/l chlorides as appropriate for receiving water quality. It is anticipated that there will be a number of requests for NPDES permits to discharge produced fluids. Discharge constituent limits will be a part of any permit issued.

Some holding pits are used as produced water storage pits until a contract hauler transports the fluids for well injection or other purposes. There is no manifest system per se, but there is registration of drilling fluid haulers with the Department and there is reporting of the producer of the fluid and its destination following transportation. Most of the fluid goes into injection wells.

There is no roadspreading or landspreading of produced fluids in Kentucky. Some use is being made currently of mechanical evaporation.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

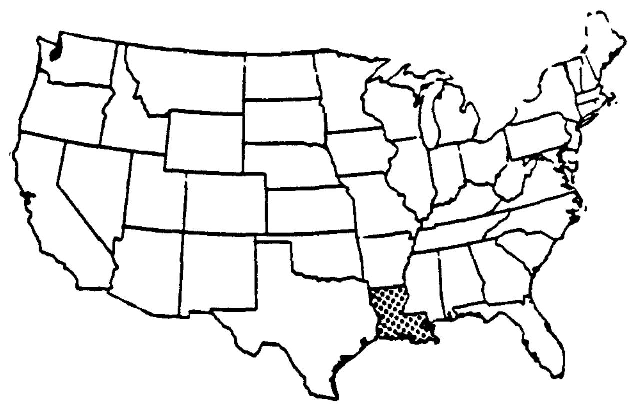
Personal Communications:

Brian C. Gelpin, Kentucky Division of Oil and Gas (606) 257-3812.

Brad Lambert, Kentucky Department of Natural Resources and Environmental Protection (502) 264-3410.

LOUISIANA

INTRODUCTION



Louisiana produced 449,545,000 barrels of oil and 5,867 x 10^9 cubic feet of gas in 1984. Louisiana ranks third in U.S. oil production and second in U.S. gas production. Over half of Louisiana's 25,823 oil wells are strippers. More than two-thirds of Louisiana's 14,436 gas wells are marginal (produce less than 60 thousand cubic feet of gas per day.) Eighty five percent of all produced fluids is salt water.

State statutes have regulated drilling operations since 1950. On January 20, 1986, the Department of Conservation promulgated amended rules and regulations regarding "the storage, treatment, and disposal of non-hazardous oilfield waste."

STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activities in Louisiana:

- Louisiana Department of Natural Resources
- Louisiana Department of Environmental Quality
- U.S. Bureau of Land Management
- U. S. Corps of Engineers

The Louisiana Department of Natural Resources Office of Conservation regulates all subsurface and surface disposal of oil- and gas-associated wastes. These powers were delegated to the Office of Conservation under Title 30 of the Revised Louisiana Statutes of 1950. The Office of Conservation has been granted primacy for all classes of UIC wells.

The Office of Conservation does not coordinate with EPA on NPDES permits, but does coordinate with the Louisiana Department of Environmental Quality, Water Quality Division, on any problem discharges originating from oil and gas activities.

The Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service. These rules, regulations, and orders are discussed in a separate section, Federal Agencies. The Bureau of Indian Affairs has some jurisdiction in limited areas of Louisiana.

STATE RULES AND REGULATIONS

DRILLING

All pits must be lined such that the hydraulic conductivity of the liner does not exceed 1×10^{-7} cm/s. Liners may consist of clays, soils, synthetics, or any combination meeting the 1×10^{-7} cm/s limitation. Pits located within inland tidal waters, lakes bounded by the Gulf of Mexico, and saltwater marshes are excempted from the liner requirement provided they are part of an approved treatment train for removal of oil and grease. Natural gas processing pits and compressor station pits are also exempted.

Louisiana State Order No. 29-B contains pit construction and closure requirements which are consistent with most States (i.e., 2-foot freeboard, pit closure within 6 months of completion, prohibition of trash and produced water into reserve pits). The Order is unusual in the perspective it uses for these requirements. The Order is written specifically so that "pits will be protected from surface waters." Another aspect of the Order is that it defines sixteen classes of oilfield waste (including drilling fluids, produced fluids, workover fluids, completion fluids, and others) as "non-hazardous oilfield wastes."

Pit closure and land treatment facilities must meet certain requirements for pH, electrical conductivity, and concentrations of certain elements. These requirements are set in Statewide Order 29-B. Reserve pits must be closed within 6 months of reaching total depth during drilling. Closure may be through annular injection, injection down another newly-drilled well which will be plugged, land treatment, solidified and buried onsite, or offsite disposal at permitted commercial facilities.

Annular injection of reserve pit fluids is allowed whenever surface casing is deep enough to protect underground sources of drinking water. Reserve pit solids may be transported offsite to a permitted commercial treatment facility for treatment and disposal. A manifest system is enforced.

PRODUCTION

Produced waters must be disposed into subsurface formations unless discharge is permitted under "applicable state or federal discharge regulatory program." Produced water may also be treated and disposed by an approved commercial facility.

REFERENCES

Louisiana State Statutes 1950 30:204.

Interstate Oil Compact Commission, Oil and Gas Compact Bulletin, Volume XLIV, No. 2, December 1985.

State of Louisiana Department of Natural Resources, Office of Conservation, "Amendment to Statewide Order No. 29-B," January 20, 1986.

Wascom, Carroll, D., "Oilfield Pit Regulations - A First for the Louisiana Oil and Gas Industry," May 30, 1986.

MARYLAND

INTRODUCTION

Maryland produced 20 million cubic feet of gas from 9 gas wells, and no oil, in 1984.

STATE REGULATORY AGENCIES

Two agencies regulate oil and gas activities in Maryland:

- Department of Natural Resources, Bureau of Mines
- Department of Health, Office of Environmental Protection

The Department of Natural Resources regulates oil handling, storage, and transportation. Drilling permits are issued, and site erosion is regulated.

All wastewater regulation is managed by the Department of Health. Section 6-104 of the public general laws of Maryland provides that a person may not dispose of any product of a gas or oil well without a permit issued by the Department. The Department has both NPDES delegation and UIC program authority.

STATE RULES AND REGULATIONS

DRILLING AND PRODUCTION

Drilling and production wastes are managed by the Department of Health, Office of Environmental Protection. There is no differentiation between pits that are associated with drilling or production activities.

A pit may be lined with an impervious material such as clay or a plastic to prevent groundwater pollution. Fluids introduced to lined pits generally are transported to a brine disposal facility or to a sewage treatment plant, or they may be transported out of State for disposal purposes. There are no requirements on thickness or type of pit liners. There is no manifest system associated with transporting gas wastes unless such wastes are defined as hazardous.

Pits that are not lined must have a groundwater discharge permit issued under Code of Maryland regulations. The requirements associated with pit contents that would meet permit conditions for a groundwater discharge are determined on a site-by-site basis. If there is a discharge from a pit, an NPDES permit would be required.

The State currently has neither issued an NPDES permit for surface discharges nor a UIC permit for underground injection. There is a groundwater discharge gas storage extraction facility in the western part of the State that is permitted to discharge about 1 million gallons per year. The permit requires that the first of a series of ten ponds be lined. There are periodic monitoring requirements for the ponds and in a nearby stream, but there are no monitoring limits and no monitoring wells.

OFFSITE AND COMMERCIAL PITS

The only offsite pit used in the State is the one in Western Maryland described above. Some transported production fluids are received by this facility.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

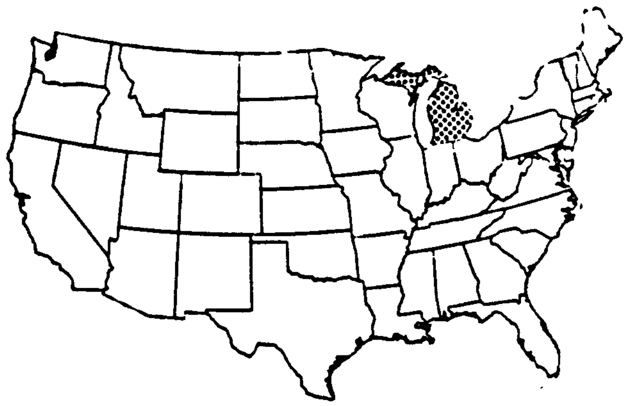
Personal Communications:

Al Hooker, Department of Natural Resources, Bureau of Mines (301) 689-4136.

Bob Creter and David Fluke, Department of Health, Office of Environmental Protection (301) 791-4787.

MICHIGAN

INTRODUCTION



Michigan produced 30,980,000 barrels of oil and 144.7 x 10^9 cubic feet of gas in 1984 from 3,848 stripper oil wells, 1,759 full-production oil wells, and 721 gas wells. In 1984, the state ranked twelfth in U.S. oil production and thirteenth in U.S. gas production. Oil and gas production in Michigan had been relatively constant for the past 5 years, but more recently oil production is down because of declining crude oil prices.

The first successful Michigan oil well was drilled in 1886. The first oil and gas drilling permit was issued in 1927.

STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activities in Michigan:

- Michigan Department of Natural Resources
- U.S. Forest Service
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency

The Michigan Oil and Gas Act of 1939 (PA 61) established the Supervisor of Wells within the Geological Survey Division of the Michigan Department of Natural Resources. The prime regulator of the oil and gas industry is the Supervisor of Wells. The Supervisor has authority to subpoena, to establish well spacing requirements, to develop orders without legislative interference, and to control disposal of solid and liquid wastes from drilling. The Oil and Gas Act provides the Supervisor of Wells broad authority to regulate the industry from "cradle to grave"; it stresses "prevention of waste" from exploration to well abandonment. The State requires a bond, an environmental assessment, and spacing minimums.

The Water Resources Commission Act of 1929 (PA 245) regulates discharges to and the pollution of any waters of the state; it is under Act 245 that National Pollution Discharge Elimination System (NPDES) permits are issued. Michigan is an NPDES delegated state with such permits issued by the Surface Water Quality Division of the Department of Natural Resources. No NPDES permits are issued for oil and gas wastes.

The Solid Waste Management Act of 1978 (PA 641) provides for the licensing of solid waste disposal sites.

The State of Michigan does not require NPDES or landfill permits for disposal of liquid or solid oil field drilling wastes; these activities are regulated by the Supervisor of Wells. Other divisions of the Department of Natural Resources provide assistance to the Geological Survey Division in enforcing the Act by providing liaison with the Attorney General and with county prosecutors for action by the local courts through cooperative efforts of Department of Natural Resources law enforcement conservation officers. Where a groundwater problem has been identified through investigation and monitoring by the Geological Survey Division, and groundwater restoration is required, an NPDES permit by the Water Quality Division is issued on the restored water.

When drilling is requested to occur on Federal lands, Federal surface ownership often is severed from ownership of mineral rights. When only surface rights are owned by the Federal government, a copy of the drilling application is sent to the Federal agency involved, generally the U.S. Forest Service. Two separate investigations then follow: one by the Geological Survey, and one by the U.S. Forest Service, which involves fish and wildlife, geological, and other Federal experts. A Federal surface use permit then is issued. The drilling application is not approved by the State until all reviews have been completed and pertinent comments made a part of permit conditions. When both surface and mineral rights are Federally owned, a copy of the drilling application is sent to both the U.S. Forest Service and Bureau of Land Management.

The U.S. Environmental Protection Agency administers the UIC program for the State (40 CFR 147.1151).

STATE RULES AND REGULATIONS

DRILLING

A letter of instruction was issued by the Supervisor of Wells on April 6, 1981, which provided for a two-pit drilling mud system--one for fresh water muds and one for salt water muds--and required that all reserve pits receiving other than fresh water fluids be lined with 20 mil PVC or an equivalent liner as approved. Instructions in 1985 require that all mud pits be lined with an impervious material that will meet or exceed specifications for 20 mil virgin PVC. Liners shall be one piece, or with factory-installed seams, and shall be installed in a manner sufficient to prevent both vertical and lateral leakage.

A revised Supervisor Instruction, effective February 1, 1985, requires that cellars shall be sealed, and rat holes and mouse holes shall be equipped with a closed-end steel liner or otherwise sealed or cased in such a manner that all fluids entering the cellar, rat hole, and/or mouse hole shall not be released to the ground but shall be discharged to steel tanks, the lined reserve pit, or the mud circulation system. Aprons of 20 mil virgin PVC or other equivalent material shall be installed under steel mud tanks and overlapping the mud pit apron, and in ditches or under pipes used for brine conveyance from cellars to pits or to steel mud tanks.

Current required practice in Michigan is for the fluids in the drilling pits to be pumped off prior to encapsulation of the pit solids. These pit fluids represent nearly 28 million gallons per year, and they have been used for drilling of additional wells, disposed in approved brine disposal wells, or spread on roads for dust and ice control. The best estimate for 1983 shows that 22 million gallons of pit brines were used for road dust and ice control. A Special Order of the Supervisor of Wells, issued March 29, 1985, banned the use of pit brines for dust control after September 1, 1985, and for ice control immediately.

For those pits that have been active since 1981, the fluid is removed and the solids are encapsulated at the site with the remaining PVC provided for such purpose, when a pit no longer is used. For those pits that may have been abandoned, or that were used prior to the Supervisor's Letter of Instruction, no action is taken unless a contamination problem has surfaced. When a potential contamination problem exists, the site is investigated by the Survey's groundwater unit. If it can be shown that an identifiable entity is responsible, damages are sought through the courts.

PRODUCTION

Over 90 percent of Michigan's brines now are disposed of by underground injection. Earthen production pits are not allowed. The Supervisor's Special Order of March 29, 1985, requires that produced brines not be used for ice control on roads and that such brines meeting certain specifications for benzene, toluene, and xylene content may be used for dust control under certain testing and approval conditions until December 31, 1987. None is to be used for such purpose after January 1, 1988.

OFFSITE AND COMMERCIAL PITS

No use is made of offsite or commercial pits in Michigan. Rule 601 of Michigan's Oil and Gas Regulations provides that brine or salt water resulting from oil and gas drilling and producing operations shall be stored, transported, and disposed of in such manner as may be approved by the Supervisor. Any brine disposal procedure which results or may result in the pollution of surface or underground fresh water resources is prohibited.

REFERENCES

Crabtree, Allen F. 1985. "Drilling Mud and Brine Waste Disposal in Michigan." Paper presented at the Reclamation Review Technical Advisory Committee Seminar/Workshop on Gel and Saline Based Drilling Wastes, Edmonton, Alberta, Canada, April 24, 1985.

Supervisor of Mineral Wells Instruction 1-84. "Use of Liners in Earthen Drilling Pits, Sealing of Cellars, Rate Holes, Mouse Holes and other Procedures to Protect Ground Waters," effective February 1, 1985.

Order of the Supervisor of Wells, Special Order 1-85, dated March 29, 1985.

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Debrabander, S. 1985. Letter Communication to EPA. Geological Survey Division, Michigan Department of Natural Resources.

Michigan Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workshop. U.S. Environmental Protection Agency, Washington, D.C. (March 26-27 in Atlanta, GA).

Personal Communications:

Bill Shaw, DNR Office of Water Quality (517) 373-8088.

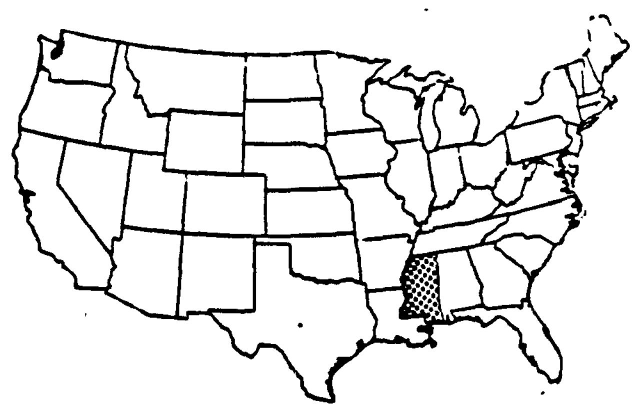
Steve Debrabander, DNR Geological Survey Division (517) 334-6976.

Rex Tefertiller, Permits, Geological Survey Division (517) 334-6974.

MISSISSIPPI

INTRODUCTION

Mississippi produced 31,879,000 barrels of oil in 1984 from 3,569 oil wells; 210 x 10^9 cubic feet of gas were produced from 715 gas wells.



STATE REGULATORY AGENCIES

Four agencies regulate the oil and gas activity in Mississippi:

- State Oil and Gas Board
- Mississippi Department of Natural Resources, Bureau of Pollution Control
- Department of Wildlife Conservation
- U.S. Environmental Protection Agency, Region IV

The State Oil and Gas Board regulates the oil and gas industry "to prevent the pollution of freshwater supplies by oil, gas or saltwater" and to promote, encourage, and foster the oil and gas industry (Section 53-1-17, State Statutes). The Oil and Gas Board does not have UIC program authority.

The Department of Natural Resources, Bureau of Pollution Control, is responsible for the investigation of water pollution and for the issuance of NPDES permits. No NPDES permits are issued for the onshore oil and gas industry.

The Department of Wildlife Conservation is responsible for the maintenance of fish and wildlife within the State.

The U.S. Environmental Protection Agency, Region IV, issues UIC program Class II injection well permits for Mississippi. In this activity area, the State Oil and Gas Board maintains a separate well injection permitting program; a well operator must obtain an injection permit both from the State and Federal Governments.

A 1982 Memorandum of Agreement among the Department of Natural Resources, Department of Wildlife Conservation, and the State Oil and Gas Board coordinates the activities of the three State agencies related to the oil and gas industry. The Agreement ensures that the Mississippi Commission on Wildlife Conservation has an opportunity to review the drill plan, as drilling may impact the sensitive environmental nature of the States's wetland resources. The Agreement, further, allows for suspension of operations by the Oil and Gas Board where any signatory agency determines such operations to be in violation of applicable laws or regulations.

STATE RULES AND REGULATIONS

DRILLING

Rule 63 of the State Oil and Gas Board provides requirements related to pits. There are generally four types of pits (other than reserve pits) permitted in Mississippi:

1. Temporary saltwater storage pits are allowed at remote sites. These must be lined, diked, and drained. They are not allowed to be filled more than 2 feet from the top. Regular inspections are required. The permit is good for 1 year. Only three such permits have been issued in the last 4 years.

2. Emergency pits are not required to be lined. They are permitted for 2 years. Three or four of these pits may be permitted in a field. Level must not exceed 1 foot in these pits. Whenever the pit is used, the Oil and Gas Board must be notified within 48 hours, and they will inspect the pit.

3. Burn pits are used to burn tank bottoms on site.

4. Well test pits are used only for test purposes. These are used rarely.

The use of drilling reserve pits or mud pits does not require a special permit; the permit to drill constitutes the permit for the drilling reserve pit. This type of pit is subject to strict stipulations regarding backfilling when drilling is completed. Rule 63 was promulgated to prevent waste by pollution of air, fresh waters, and soils. Extensive management conditions are presented in the Rule with each of the above pit descriptions.

Mississippi allows annular reinjection of drilling fluids. Seven annular reinjection wells are operating in Mississippi. These are used only when no other economical disposal method is available. Mississippi requires radiological surveys of annular reinjection wells every 6 months to determine where the reinjected fluids are going. Pit muds may be pumped into a dry well hole, or they most often are buried on site. Land farming is used in Mississippi. Muds act as a low-grade fertilizer.

PRODUCTION

Production fluids are reinjected. Reinjection of brines is operationally feasible state-wide. Since 1978, no method of brine disposal other than reinjection has been considered acceptable in Mississippi.

OFFSITE AND COMMERCIAL PITS

Except for two commercial pits in Southern Mississippi, both of which are phasing down, use is not made of offsite and commercial pits within the State.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Mississippi Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workshop. U.S. Environmental Protection Agency, Washington, D.C. (March 26-27 in Atlanta, GA).

Statutes and Statewide Rules and Regulations, State of Mississippi, State Oil and Gas Board, Revised 7/1/86.

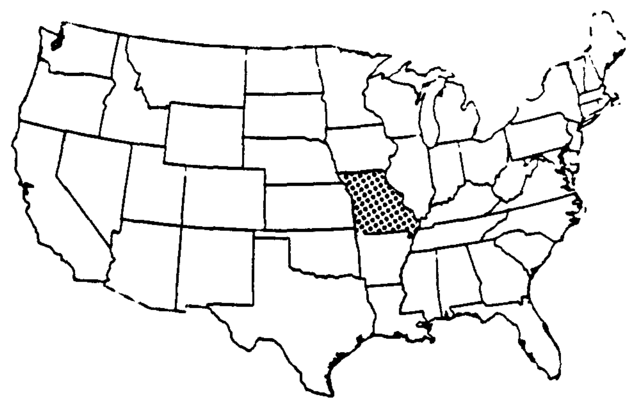
Personal Communication:

Richard Lewis, Mississippi Oil and Gas Board (601) 359-3725.

Jerry Cain, Mississippi Department of Natural Resources, Bureau of Pollution Control (601) 961-5073.

MISSOURI

INTRODUCTION



Missouri produced 131,000 barrels of oil from 557 oil wells and no gas in 1984. The State has 9 evaporation pits and 229 injection wells. In 1984, Missouri had a total of 1.9 million barrels of produced waters and 2.6 million barrels were injected. The reason for injection exceeding production is that two major steam operations import fresh water to steam out the oil, which results in an increased quantity of injectable fluids. Missouri has not had gas production since 1977.

STATE REGULATORY AGENCIES

Three agencies regulate oil and gas activities in Missouri:

- Department of Natural Resources, State Oil and Gas Council
- U.S. Bureau of Land Management
- Department of Natural Resources, Division of Environmental Quality

The State Oil and Gas Council was formed by Rule 10 CSR 50-1.010 and is composed of the executive heads of the Division of Geology and Land Survey, Division of Commerce and Industrial Development, Missouri Public Service Commission, Clean Water Commission, the University of Missouri, and two persons knowledgeable of the oil and gas industry appointed by the Governor with the advice and consent of the Senate. The State geologist is charged with the duty of enforcing the rules, regulations, and orders of the Council. The State has primacy for UIC program Class II wells.

Federal lands in Missouri are confined to U.S. Air Force bases. There is drilling on such lands. When a request for a permit to drill is received, the Bureau of Land Management prepares the draft permit, which is issued by the State Oil and Gas Council.

The Department of Natural Resources, Division of Environmental Quality becomes involved only when there is a breach of a pit dike because of heavy rains, or because of another reason, and a spill of fluids occurs. Appropriate action under the Division of Environmental Quality regulations then occurs.

STATE RULES AND REGULATIONS

DRILLING

Rule 10 CSR 50-2.040 provides requirements during the drilling of wells to prevent contamination of either surface or underground fresh water resources. There is a bonding requirement before commencing oil or gas drilling operations, and all wells must be plugged when abandoned.

There are no regulations related to drill pits. Drill pits are not lined. When pit muds dry, the muds are buried on site.

PRODUCTION

There are no regulations related to construction of evaporation-percolation pits for produced waters. About a third of the produced waters are allowed to evaporate-percolate in such pits, much of the produced water is injected into a Class II well, and some of it is trucked off property.

OFFSITE AND COMMERCIAL PITS

Some of the produced fluid is trucked off the property associated with the producing field. Some may cross a State line. There is no manifest required of the transported fluids.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Missouri Meeting Report. 1985. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. U.S. Environmental Protection Agency, Washington, D.C. (December 1985).

Rules and Regulations of Missouri Oil and Gas Council, June 1985.

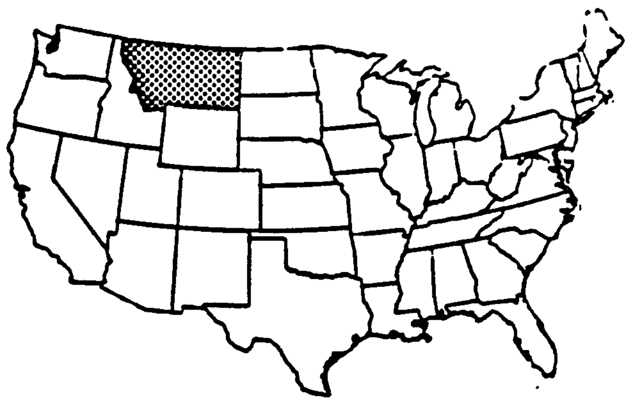
Personal Communication:

Kenneth Deason, Missouri Oil and Gas Council (314) 364-1752.

MONTANA

INTRODUCTION

Montana produced 29,762,000 barrels of oil and 56.9×10^9 cubic feet of gas in 1984. Production is from 4,665 oil wells and 2,152 gas wells. A total of 622 wells were drilled for oil and gas in 1985. About 320,000 barrels of brine per day are produced from the approximately 1,600 full producing oil wells. The remaining stripper wells produce about 40 barrels each of brine per day.



STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activities in Montana:

- Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division
- Montana Department of Health and Environmental Sciences, Water Quality Bureau
- U.S. Environmental Protection Agency, Region VIII
- U.S. Bureau of Land Management

The Oil and Gas Conservation Division issues drilling permits and regulates the oil and gas industry in Montana. There is a compliance bond. Montana does not have primacy for the UIC program.

The Montana Department of Health and Environmental Sciences, Water Quality Bureau, controls water quality issues. The Bureau has primacy for the issuance of NPDES permits.

Region VIII of the Environmental Protection Agency issues UIC permits for the injection of brines in Montana.

The Bureau of Land Management uses their own form for drilling permits; thus, a driller must obtain a State as well as a Federal permit to drill for oil or gas on Federal lands. The Oil and Gas Conservation Division has a cooperative agreement with the Bureau of Land Management regarding treatment of Indian lands. Normally, the State issues the permits to drill on Indian lands.

STATE RULES AND REGULATIONS

DRILLING

Permits are not required for drilling pits. If a dry hole is encountered, fluids from the drill pit normally are pumped to the drill hole prior to well plugging. Or, the liquids may be moved to an oil field reserve pit. The pit solids are allowed to dry, the pit is closed, and the surface reclaimed.

PRODUCTION

Rule 36.22.1227 of the Board of Oil and Gas Conservation states that salt or brackish water may be disposed of by evaporation when impounded in excavated earthen pits which may only be used for such purpose when the pit is underlaid by tight soil such as heavy clay or hardpan. At no time shall salt or brackish water impounded in earthen pits be allowed to escape over adjacent lands or into streams. Rule 36.22.1228 allows salt water to be injected into the stratum from which produced or into other proven saltwater-bearing strata.

The lining requirement of production reserve pits is decided case by case, based upon soil composition, slope, drilling fluids, and proximity to water sources. Fluids may be removed from reserve pits by several methods. One method is to remove fluids by truck and haul them to another drill site or disposal facility. No manifest is required for transporting fluids. Another method is to allow fluids, other than oil, to remain in a reserve pit for up to a year for evaporation. Most produced water is reinjected underground. Another method is to chemically treat the fluids so that they may be used for beneficial purposes. After the fluids have been removed, the remaining solids are left to dry before backfilling. If a plastic liner has been used, it is folded into and buried in the reserve pit.

NPDES discharge permits are issued by the Water Quality Bureau of the Montana Department of Health and Environmental Sciences for 10 to 12 production reserve pits under the beneficial use provision of the wildlife and agricultural use subcategory. Of those issued, only about two of the permitted facilities discharge. Discharges are to a closed basin in the northern part of the State. Discharge limits include total dissolved solids of less than 1,000 mg/l and an oil and grease of 15 mg/l absolute with an average of 10 mg/l. Other discharge limits including phenols and metals are imposed.

OFFSITE AND COMMERCIAL PITS

Use is not made of offsite and commercial pits in Montana.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Personal Communications:

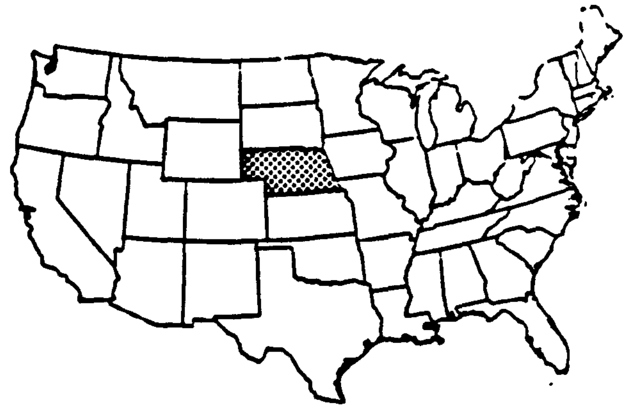
Charles Maio, Administrator, Board of Oil and Gas (406) 656-0040.

Abe Horpestad, Water Quality Bureau (406) 444-2459.

NEBRASKA

INTRODUCTION

Nebraska produces 6,470,000 barrels of oil and 2,347 MM cubic feet of gas each year. Production is from 2,072 oil wells and 18 gas wells. Most of the State production is in two areas: the five county area in the Denver Basin, and Red Willow and Hitchcock Counties. Strippers account for about 85 percent of the State production.



STATE REGULATORY AGENCIES

Three agencies regulate oil and gas activity in Nebraska:

- Nebraska Oil and Gas Conservation Commission
- Nebraska Department of Environmental Control
- U.S. Bureau of Land Management

The Nebraska Oil and Gas Conservation Commission regulates industry practices and procedures with regard to construction, location, and operation of onsite drilling. The Commission issues permits for oil and gas drilling and UIC Class II wells. The Commission has three members who are appointed by the Governor. At least one member must have experience in oil or gas production.

Nebraska is an NPDES-delegated State. The Nebraska Department of Environmental Control issues all NPDES permits and regulates all other classes of UIC wells.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. The Bureau is addressed in a separate section.

STATE RULES AND REGULATIONS

DRILLING

Under Commission Rule 3.022, retaining pits must be permitted. Upon receipt of Form 15, Retaining Pit Permit, a Commission representative will approve or disapprove a proposed retaining pit. These pits are required to be lined or constructed with impermeable material and must have the capacity for at least 3 days of facility fluid influx. This rule does not apply to reserve pits, emergency pits, or burn pits. Burn pits are required to be a safe distance from any other structure and shall be constructed so as to prevent any materials escaping the pit or surface water entering the pit. The regulations do not address any requirements for reserve pits. Open pit storage of oil is not allowed unless during an emergency or by special permission by the Director of the Commission.

PRODUCTION

Commission regulations on brine disposal do not distinguish between well types. Under Rule 3.002, "No salt water, brackish water, or other water unfit for domestic, livestock, irrigation or general use shall be allowed to flow over the surface or into any stream or underground fresh water zone." Brine may be disposed by evaporation pits, road spraying, or injection. Brine pits fall under the regulations in Rule 3.022. Road spraying of brine is considered on a case-by-case basis. When allowed, spraying must be done with a spreader bar and in such a way as the prevent runoff.

Brine can be disposed by injection into either a disposal well or an enhanced recovery well. Both types of injection wells are regulated by the Commission. Under Rule 4.005.01, "Each enhanced recovery well or disposal well shall be completed, equipped, operated, and maintained in a manner that will prevent pollution of fresh water or damage to sources of oil and/or gas and will confine injected fluids to the formations or zones approved." Annular injection is prohibited. Authorization of injection into disposal or enhanced recovery wells remains valid for the life of the well unless revoked by the Commission.

OFFSITE AND COMMERCIAL PITS

This subject is not addressed in the Commission regulations.

REFERENCES

Nebraska Oil and Gas Conservation Commission, Rules and Regulations, December 1985.

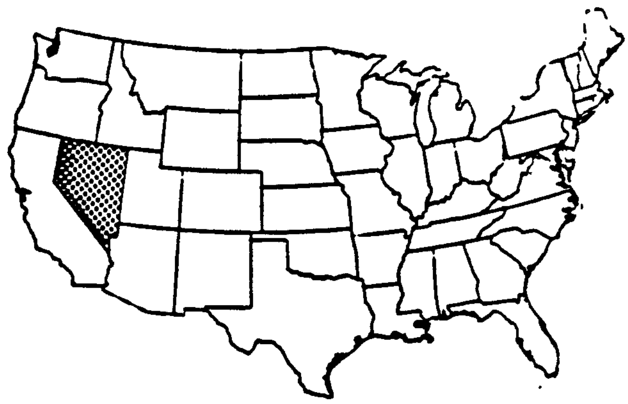
The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Coubrough, Rob, State Regulatory Information Submitted in 1985.

Nebraska Meeting Report. 1985. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. U.S. EPA, Washington, D.C. (December 1985).

NEVADA

INTRODUCTION



During 1984, Nevada produced 1,953,000 barrels of oil from a total of 34 oil wells. There are no producing gas wells in this State. All of these wells are on Federal land and most use reserve pits to evaporate drilling fluids. Reinjection is applied to produced waters. Between 200,000 and 500,000 barrels per year of brine are produced in Nevada's major production area (the Carbonate Belt). Reinjection of these waters is accomplished collectively into some 5-9 injection wells. No produced waters are discharged under the beneficial use subcategory. Nevada does not have NPDES primacy.

STATE REGULATORY AGENCIES

For agencies regulate the oil activity in Nevada:

- Nevada Department of Minerals
- Nevada Department of Conservation and Natural Resources, Division of Environmental Protection
- Bureau of Land Management
- EPA, Region IX, Underground Injection Section

The Nevada Department of Minerals, created as a single State department by the State legislature in 1983, regulates the industry on the State level with respect to construction, location, and operation of onsite drilling and production. All operation permits are issued from this department.

The Division of Environmental Protection in the Department of Conservation and Natural Resources currently is developing a program to obtain UIC primacy. The Division has regulations pertaining to major spills.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. For such drilling, the Bureau of

Land Management handles all Applications to Drill. The Bureau requires extensive environmental documentation, including environmental assessments, and develops environmental impact statements for drilling on Federal land.

EPA's Region IX regulates the reinjection of produced fluids under the UIC program.

STATE RULES AND REGULATIONS

The Regulations and Rules of Practice and Procedures under Chapter 522 of the Nevada Revised Statutes of the Oil and Gas Conservation Law were adopted by the Department of Minerals on December 20, 1979. Section 200.1 of these rules states that, "Fresh water must be protected from pollution whether in drilling, plugging or producing oil or gas or in disposing of salt water already produced." The regulations govern the "drilling, safety, casing, production, abandoning and plugging of wells." The regulations do not include a provision for allowing or disallowing discharges nor is their mention of a discharge allowance. Section 308, however, states that all excavations must be drained and filled and the surface leveled so as to leave the site as near to the condition encountered when operations were commenced as practicable. Section 407 further states that "Oil or oil field wastes may not be stored or retained in unlined pits in the ground or open receptacles except with the approval of the Division." Section 600.1 states that, "The underground disposal of salt water, brackish water, or other unfit for domestic, livestock, irrigation or other use, is permitted only upon approval of the Administrator."

Region IX regulates the underground injection of wastes from oil wells under the UIC program. The applicable regulations are found in 40CFR 144 and 146.

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Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. Summary of presentation given by Scott McDaniel, Nevada Department of Minerals. December 1985.

Nevada Department of Conservation and Natural Resources, Division of Mineral Resources. _Regulations and Rules of Practice and Procedures._ Chapter 522. December 20, 1979.

Personal Communications:

Cathy Loomis, Engineering Technician, Nevada Department of Minerals, September 26, 1986 (702) 885-5050.

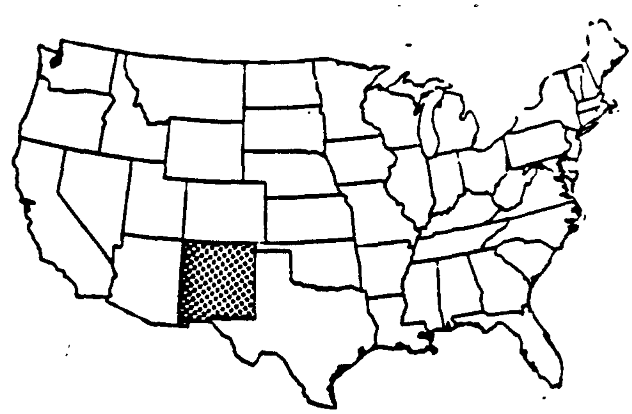
Dan Gross, Division of Environmental Protection, Department of Conservation and Natural Resources, September 26, 1986 (702) 885-4670.

Ellis Hammett, Permit Processor, Nevada Bureau of Land Management, September 26, 1986 (702) 784-51236.

Nate Lau, Director, UIC Division, EPA Region IX, September 26, 1986 (415) 974-0893.

NEW MEXICO

INTRODUCTION



New Mexico produced 75,532,000 barrels of oil and 965.7 x 10^9 cubic feet of gas in 1984, ranking fourth in U.S. gas production and eighth in U.S. oil production. Production is from 24,954 oil wells and 17,523 gas wells. Twenty percent of oil production is from the stripper well category.

STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activities in New Mexico:

- New Mexico Energy and Minerals Department
- New Mexico Water Quality Control Commission
- U.S. Bureau of Land Management
- Indian Tribes

The New Mexico Energy and Minerals Department, Oil Conservation Division, is responsible for regulating the oil and gas industry. It regulates exploration and drilling, production, and refining with respect to protection of water quality.

New Mexico has very few statewide specific rules relating to oil and gas activities because of the diversity of the climate, diversity of the geology, and diversity of the quantity and type of waste that is produced. There is a plugging bond requirement that endures until well abandonment has been approved by the Division.

The U.S. EPA has the responsibility for NPDES permitting in New Mexico; however, the State Environmental Improvement Division certifies those permits. No NPDES permits have been issued for the New Mexico oil and gas industry drilling and production facilities.

The New Mexico Water Quality Control Commission, Environmental Improvement Division, is prohibited from taking any action which would interfere with the exclusive authority of the Oil Conservation Commission over all persons and things necessary to prevent water pollution as a result of oil or gas operations. The Environmental Improvement Division administers and enforces Commission regulations at brine manufacturing operations and concerning discharges to ground or surface waters at brine manufacturing operations, including all brine production wells, holding ponds, and tanks. The Oil Conservation Division regulates brine injection through its Class II UIC program if the brine is used in the drilling for or production of oil and gas. The Environmental Improvement Division regulates brine injection through its UIC program if the brine is used for other purposes.

The U.S. Bureau of Land Management takes the lead on oil and gas drilling activities on Federal lands. Where drilling on Federal land occurs, two drilling permits would be issued--one from the Bureau of Land Management and one from the State. The State would maintain primacy in waste disposal activities associated with any such drilling or production activities.

Issues with drilling on Indian lands currently remain unresolved. Some Tribes have issued regulations concerning oil and gas drilling and production activities. Some Tribes have applied for UIC program delegation. The State has not waived jurisdiction in regard to regulating the oil and gas industry on Indian lands, however. Where Tribe regulations go beyond those of the State, the Tribe regulations prevail.

STATE RULES AND REGULATIONS

DRILLING

No drilling fluids are authorized to be discharged to surface waters. Drilling fluids must be disposed of at the well site in a manner to prevent water contamination; they cannot be removed to another site without approval of the District Supervisor. There is a fine of $1,000 per day for violating this rule. All drilling and reserve pits must be built large enough to hold all drilling mud and waste fluids at each well location.

The Rules and Regulations are general and allow for a great deal of flexibility in managing day-to-day situations. Different district managers manage conditions with some variation from district to district, which leads to a case-by-case approach in management.

Commission Rule 310 requires that all oil or distillate tanks, the location of which constitutes an objectionable hazard, be surrounded by a dike or fire wall having a capacity one-third larger than the capacity of the enclosed tanks. Any tank used in the oil and gas industry and located within 1,000 feet of a river or irrigation canal is deemed to be a hazard under this rule and is required to have a fire wall or dike constructed.

PRODUCTION

In 1985, a modified statewide produced water rule was promulgated by the Oil Conservation Division that prohibits disposal on the surface of the ground or in any pit, pond, lake, depression, draw, stream bed, arroyo, in any water course, or in any other place or in any other manner which constitutes a hazard to fresh water supplied. Fresh water is defined as water having 10,000 mg/l or less of total dissolved solids, unless it is found that there is no reasonably foreseeable beneficial use which would be impaired by contamination of such water. Produced water may be used in road construction with approval of the District Supervisor.

There are 1985 requirements that evaporation pit linings must be approved. The New Mexico Oil Conservation Division has issued guidelines for pit liners and below-grade storage tanks, and applications are now being accepted under the order that was adopted in June 1985.

There are two specific orders requiring disposal of produced water in New Mexico. One order instituted in 1969 bans all disposal in unlined pits in the southeastern part of the State. The second order requires that no unlined pits receive more than five barrels per day in shallow groundwater areas in northwest New Mexico.

In 1984, 337 million barrels of brine were produced from oil wells, and another 5.5 million barrels were produced from natural gas, for a total of 342 million barrels. One hundred fifty-three million barrels were disposed of in injection wells for secondary recovery and pressure maintenance. Approximately 43 percent of the state's oil yield is produced through secondary recovery and pressure maintenance wells. One hundred fifty-nine million barrels were injected into saltwater disposal wells. There are roughly 4,500 injection wells for secondary recovery and another 300 injection wells for salt water disposal. Thirty-one million barrels of produced water were disposed of in permitted ponds or in unlined pits, or were used as secondary recovery makeup water. Most of the produced water is disposed by injection and a very small percent is disposed of using surface methods. None of these surface methods includes disposal into any streams or water courses.

Contamination now is being detected related to oil and gas activities which occurred three or four decades ago. These cases may be related to improper casing, pit construction, or any number of practices. Little groundwater monitoring has been done, so the extent of damage is unknown.

OFFSITE AND COMMERCIAL PITS

Operators trucking pit contents away from a sensitive area of the State must dispose of the fluids in a pond approved for groundwater protection. Some of these sites are located high atop mesas where there are unsaturated geological strata. Little, if any, groundwater contamination is expected from these sites.

Three different offsite disposal methods have been approved. The first involves moving the drilling mud to another drilling pit. The second is land application. The third is to seal stock watering ponds and catch ponds in the San Juan basin. In the latter case, the operator and the land owner coordinate with the Soil Conservation Service, which has standards for the application of these materials to pond soils.

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Memorandum, R. L. Stamets, Director, Oil Conservation Commission, regarding Hearings for Exceptions to Order No. R-3221, dated October 22, 1985.

Personal Communication:

David Boyer, Hydrogeologist, New Mexico Oil Conservation Division, (505) 827-5802.

NEW YORK

INTRODUCTION

New York is one of the pioneer States for oil and gas production and use. Proven oil reserves were documented in 1627, and drilling began in the late 1800s. Since then it is estimated that 30,000 to 50,000 wells have been drilled in New York.

New York produced 952,000 barrels of oil from 4,678 wells in 1984. Twenty-seven billion cubic feet of natural gas was produced from 3,800 gas wells in 1984.

REGULATORY AGENCIES

BACKGROUND

In 1963 the New York legislature passed laws regarding oil and gas operations. A working permitting system was instituted in 1966 under the purview of the Department of Environmental Conservation. The regulations have been revised fairly often over the last twenty years. In fact, further revisions are expected in the next year or two as a result of a Generic Environmental Impact Statement scheduled for completion in mid-1987.

AGENCIES

Oil and gas activities in New York are regulated by:

- NY Department of Environmental Conservation
- Bureau of Land Management (Federally-held mineral rights only)
- U.S. Forest Service (surface activities in U.S. forests)

Most oil and gas activities in New York are regulated by the Department of Environmental Conservation. The Department of Environmental Conservation is authorized to regulate the "development, production, and utilization of natural resources of oil and gas . . . in such a manner that a greater ultimate recovery of oil and gas may be had." The Department also has authority for "prevention of pollution and migration." New York is NPDES-delegated, with the Department of Environmental Conservation responsible for the program. New York does not have UIC primacy.

The Department of Environmental Conservation is not entirely independent. Within the Department of Environmental Conservation, the Oil, Gas, and Solution Mining Advisory Board (with a majority of industry representatives) has input in the development of rules and regulations.

The U.S. Bureau of Land Management has regulatory authority for oil and gas activities when mineral rights are Federally held. Their regulations are discussed in a separate section, Federal Agencies.

The U.S. Forest Service has jurisdiction over surface activities on federal forest lands even when mineral rights are held privately.

The Water Quality Division, Fish and Wildlife Division, Regulatory Affairs, Law Enforcement, and Lands and Forests provide instrumental manpower and enforcement actions, when applicable.

RULES AND REGULATIONS

DRILLING

The Division of Mineral Resources (within the Department of Environmental Conservation) issues all oil and gas drilling permits. Each permit requires that the fluids generated by drilling be "hauled away and properly disposed of." The regulations are unclear regarding what practices constitute proper disposal.

"Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited." Part 554 Section 554.1 of the Mineral Resources Regulations requires the operator "to submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids." Drilling muds are specifically excluded from this requirement; "Drilling muds are not considered to be polluting fluids." Drilling pits are dewatered and the fluid disposed of properly prior to reclamation. During reclamation, pit liners are shredded or removed and the rock cuttings disposed in situ. After drying, the cuttings are buried.

Other drilling wastes must be disposed or discharged in a manner acceptable to the Department considering the environmental sensitivity and geology of the area. Historical experience with drilling operations in the same area may also be used in considering an application. Permits may be required for disposal or discharge of drilling wastes (excluding drilling muds) in addition to the drilling permit. Drilling muds are not defined in the regulation; it is unclear whether this term is intended specifically for rotary drilling muds, or if the term is inclusive of all fluids used in drilling. Ninety-five percent of New York drilling utilizes rotary <u>air</u> drilling technology.

Brine and salt water generated during drilling are considered "polluting fluids" in the Mineral Resources Regulations. These fluids, and other polluting fluids, may be stored in watertight tanks or earthen pits for up to 45 days after drilling ends prior to disposal. An extension may be granted if the operator plans to use the fluids for later activities. The regulations do not specify what disposal alternatives may be ultimately acceptable for disposal of brines and salt water generated during drilling.

The Department is also responsible for well construction, spacing, and plugging requirements.

PRODUCTION

Part 556 of the Mineral Resources Regulations addresses operating practices applicable to oil and gas wells. Section 556.5 prohibits pollution of the land and/or surface or ground fresh water resulting form producing, refining, transportation, or processing of oil, gas, and products. Brine (i.e., produced water) may be stored in water-tight tanks or in earthen pits prior to disposition. Although specific construction requirements are not described in the regulation, earthen pits must be constructed to prevent percolation into the soil, over or into adjacent lands, streams, or bodies of water.

The only disposal alternative described in the regulation is injection. The Department of Environmental Conservation has procedures for application and approval of permits to inject brines.

Although the regulations do not address road spreading, it is the predominant brine disposal method in New York. Road spreading is conducted on a manifest system under a separate permit.

Although it is not discussed in the regulations, the Department of Environmental Conservation allows "processing [of brines] at sewage disposal plants, permitted onsite discharges, and hauling to other states with approved disposal facilities." Brine discharges from stripper wells is permitted under the following limitations:

- oil and grease	15 mg/l
- pH	6 to 9
- benzene	10 micrograms/l
- toluene	10 micrograms/l
- xylene	10 micrograms/l

Sampling is done infrequently on any given well. Annular disposal is not allowed.

OFFSITE PITS

New York regulations do not address the use of offsite pits for long term storage or disposal.

REFERENCES

Interstate Oil Compact Commission, The Oil and Gas Compact Bulletin, Volume XLIV, Number 2, December 1985.

Cornell University, "Oil, Gas and Solution Mining Legislation in New York As Amended through September 1985."

New York State Statute 550.2, Subchapter B - "Mineral Resources," Parts 550 through 558, as amended.

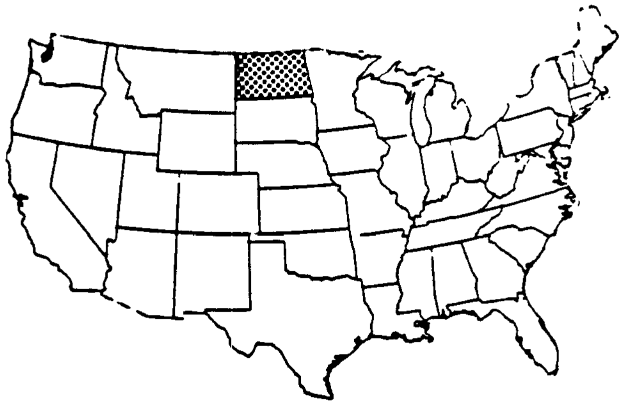
New York State Environmental Conservation Law, Article 23, Title 1-5 (circa 1985).

New York Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workskop, U.S. EPA, Washington, D.C., March 26-27 in Atlanta, GA). July 1985.

NORTH DAKOTA

INTRODUCTION

North Dakota produced 52,654,000 barrels of oil and 80 x 10^9 cubic feet of gas in 1984. Production is from 4,026 oil wells and 58 gas wells. This 1984 figure for oil production established a record high production figure for the State.



STATE REGULATORY AGENCIES

Three agencies regulate oil and gas activity in North Dakota:

- North Dakota Industrial Commission
- U.S. Department of Agriculture, Forest Service
- U.S. Bureau of Land Management

The North Dakota Industrial Commission, Oil and Gas Division, has the regulatory responsibility to oversee the drilling and production of oil, protect the correlative rights of the mineral owners, prevent waste, and protect all sources of drinking water. Other responsibilities of the Division are to collect monthly reports on oil, gas, and water; oversee proper disposal of brine; and issue drilling permits. The Division also has primacy for UIC Class II wells and issues such permits.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. When drilling is to occur on U.S. forestland, no additional permit is needed but additional stipulations are placed by the U.S. Forest Service.

STATE RULES AND REGULATIONS

DRILLING

Before a drilling permit is issued by the Commission, the operator of the well must be bonded. Single well bonds are \$15,000, a ten-well bond is \$50,000, and a blanket bond is \$100,000. The Commission will release the bond after site restoration is approved. Before drilling activities, Commission inspectors will survey the site for pit location. The inspectors also decide whether or not to require a pit liner at the site.

Under Commission Rule 43-02-03-19, "Pits shall not be located in, or hazardously near, stream courses, nor shall they block natural drainages. Pits shall be constructed in such manner so as to prevent contamination of surface or subsurface waters by seepage or flowage therefrom. Under no circumstances shall pits be used for disposal, dumping or storage of fluids, wastes and other debris not used in drilling operation." Within 1 year after the completion of a well, the pit site must be restored. Pit restoration does require approval from the Commission. Reclamation includes redistributing topsoil that was removed from the site at the beginning of drilling activities.

When drilling is on U.S. forest lands, the U.S. Forest Service has additional stipulations on top of those of the Commission. The Forest Service requires a complete survey and design of the drilling site. This survey must be approved before drilling. All reserve pits must be lined with a material that has a minimum burst strength of 150 psi. Tanks must be diked. The site reclamation plan must also be approved by the Forest Service before implementation.

PRODUCTION

Under Commission Rule 43-02-03-53, "All saltwater liquids or brines produced with oil and natural gas shall be disposed of without pollution of freshwater supplies. At no time shall saltwater liquids or brines be allowed to flow over the surface of the land or into streams." Surface pits are not allowed for brine storage. Surface tanks are allowed provided they are diked and are leak-proof. Brine may be disposed by use of injection wells or disposal wells; both methods require permits issued by the Commission.

When a central tank battery or central production facility is planned to be used, approval must be received from the Commission or by the forest Service if on U.S. forest lands.

OFFSITE AND COMMERCIAL FACILITIES

Offsite pits are not addressed in the Commission regulations. Offsite treatment facilities require a permit from the Commission. Before treatment operations commence, the facility is required to put up a bond of $25,000 to the Commission.

REFERENCES

North Dakota Industrial Commission, Statutes and Rules for the Conservation of Oil and Gas. January 1985.

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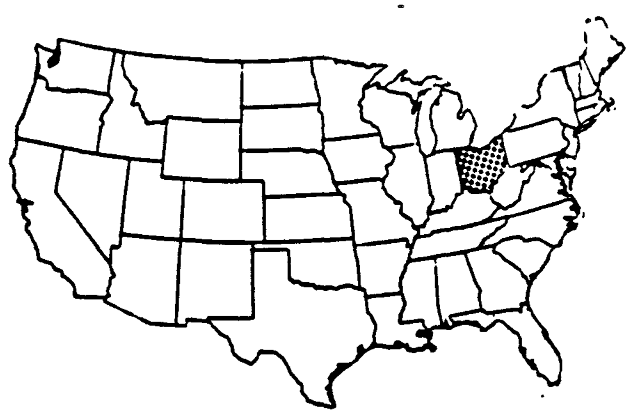
U.S. EPA. North Dakota Meeting Report. Proceedings of Onshore Oil and Gas State/Federal Western Workshop. U.S. EPA, Washington D.C. (December 1985).

U.S. Department of Agriculture, Special Forest Service stipulations, September 1986.

OHIO

INTRODUCTION

Ohio produced 15,271,000 barrels of oil and 186.5 x 10^9 cubic feet of gas in 1984 from 1,830 full producing oil wells and approximately 24,263 stripper wells producing less than 10 barrels per day, and 14,762 full producing gas wells and approximately 60,000 stripper wells producing less than 60,000 cubic feet per day.



STATE REGULATORY AGENCIES

Two agencies regulate oil and gas activities in Ohio:

- Ohio Department of Natural Resources
- Ohio Environmental Protection Agency

The Ohio Department of Natural Resources, Division of Oil and Gas, issues permits for oil and gas drilling and for underground brine injection. The statutes and rules of the Division of Oil and Gas do not contain provisions for effluent discharges. The Division operates on revenues from permit and other similar fees. Enforcement activities are dependent primarily upon approximately 50 field staff employees who inspect well sites and conduct investigations. The Division of Oil and Gas has authority to review, investigate, and require corrective action related to all oil and gas drilling and production activities. Compliance bond and well spacing are requirements of the Division.

Ohio has been delegated NPDES authority. NPDES permits are issued through the Ohio Environmental Protection Agency, Water Quality Division; none is issued for the oil and gas drilling and production industry. The jurisdiction of the Ohio EPA extends to any pollution of the waters of the State. Where brine spills may impair waters of the State, for example, there is coordination between the Ohio DNR and Ohio EPA in damage assessment and corrective measures. When there is potential for groundwater contamination, the Ohio Environmental Protection Agency may assist in the investigation and joint charges may be filed with the Ohio Department of Natural Resources.

A five-member oil and gas Board of Review was created by statute within the Ohio Department of Natural Resources with 5-year terms consisting of representatives of a major petroleum company, the public, independent petroleum operators, one learned and experienced in oil and gas law, and one learned and experienced in geology, as appointed by the Governor. Any person claiming to be aggrieved or adversely affected by an order of the Chief of the Division of Oil and Gas may appeal to the Board for an order vacating or modifying such an order.

Rarely, there is oil and gas drilling on Federal lands. When application for such drilling is filed, the permittee obtains a lease from the appropriate Federal authority prior to requesting a permit from the Division of Oil and Gas. The permitting process then is managed as a standard procedure with no special coordinating efforts.

STATE RULES AND REGULATIONS

DRILLING

Pursuant to Section 1509.22 of the Ohio Revised Code, substances resulting, obtained, or produced in connection with the exploration, drilling or production of oil and gas must be injected into an underground formation approved by the Chief, Division of Oil and Gas, or disposed by an approved alternative method. Alternative methods include annular disposal, disposal in association with an enhanced recovery project, or road spreading for dust and ice control.

Earthen brine pits may have caused most of Ohio's contamination problems. Pursuant to recently enacted legislation, pits are required to be water tight either by clay or plastic liner. A pit life beyond 180 days is prohibited. Pits will be allowed only for drilling, reconditioning, plugging, or other limited use.

In most cases, pit solids are buried on the well site when no environmental harm is expected. When there is a history of groundwater problems associated with an area, a plastic liner requirement is made a part of the drilling permit.

PRODUCTION

Recently enacted laws, which became effective on April 12, 1985, established new standards for well operators and waste brine transporters. Brine disposal is one of the major problems in Ohio. Well drillers now are required to submit a brine disposal plan identifying the transporter of the brine including the transporter's address. Anyone who transports brines must pay a $500 one-time fee, provide a $300,000 certificate of insurance for bodily injury and liability, post a $15,000 bond to be used in paying for damages, and provide detailed information. The detailed information includes a daily log that identifies ultimate brine disposal such as time and date of brine loading and amount, road spreading location, disposal well permit number, time and date of brine disposal, etc. The driver is required to maintain a daily log showing driver name, registration certificate number, sites visited, and destination. Brine production is estimated at 160,000 barrels per day.

For road or land spreading, a township must pass a resolution to allow brine disposal that meets five minimum requirements: it must regulate the rate and amount of application, prohibit spreading when ground is water saturated, regulate the spreader speed, require use of a dispersion bar, and prohibit direct spray on vegetation. The resolution then is considered for approval by the Department of Natural Resources.

When a well is abandoned, following permission for such by the Division Chief, a detailed report containing information and names and addresses of witnesses to the plugging of the well must be signed and filed by the owner and operator of the well. When a well is plugged, the drill site must be restored, the area including pit site is to be returned to its natural contour, all trash is to be removed, and the site is to be seeded.

OFFSITE AND COMMERCIAL PITS

When such a groundwater problem history exists, pit solids may be required to be removed and transferred to an Ohio EPA regulated disposal site. Or, if there is a request to move pit solids to an offsite area, an EP-toxicity test for hazardous waste characteristics is required prior to a transfer to a State-approved hazardous or nonhazardous landfill, as appropriate. Abandoned pits are investigated when alleged to be the cause of a groundwater problem. When found to contribute to such a problem, the owner of the pit is required to remove solids and transport them to a State-approved solids disposal facility.

REFERENCES

Chapter 1509 of the Ohio Revised Code.

Chapter 1501, Rules of the Division of Oil and Gas of the Ohio Department of Natural Resources.

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Personal Communications:

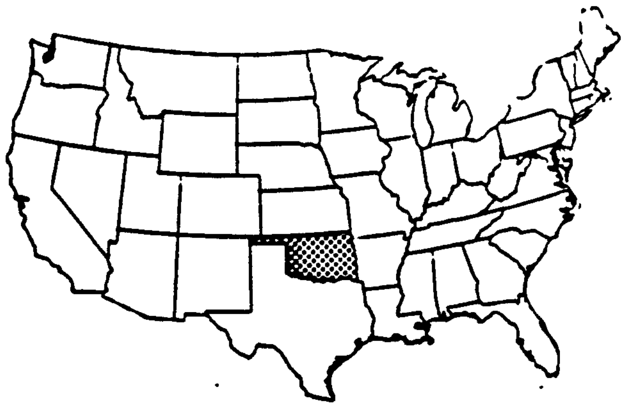
David A. Hodges, DNR, Division of Oil and Gas (614) 265-6917.

Ted De Brosse, DNR, Division of Oil and Gas (614) 265-6894.

OKLAHOMA

INTRODUCTION

Oklahoma produced 153,250,000 barrels of oil and 1,996 x 10^9 cubic feet of gas in 1984. It ranked fifth in U.S. oil production and third in U.S. gas production. Oklahoma had 99,030 producing oil wells and 23,647 producing gas wells. There are approximately 200 million barrels of salt water produced by the oil industry per year. There are about 5,200 saltwater disposal wells and 9,900 enhanced recovery injection wells. Approximately 100 of the disposal wells are commercial facilities.



STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activities in Oklahoma:

- Oklahoma Corporation Commission, Oil and Gas Conservation Division
- Oklahoma Department of Health Water Resources Board
- Osage Indian Tribe
- U.S. Bureau of Land Management

The Oklahoma Corporation Commission has the exclusive jurisdiction for regulating the disposal of waste from oil and gas activities. Pollution of surface or subsurface water during any well activity is prohibited. Currently, there are 55 inspectors who have the authority to shut down operations if regulations are not followed. Well activity is defined in Rule 3-101 as exploration, drilling, producing, refining, transporting, or processing of oil and gas. Oklahoma has received primacy for the UIC program.

The Water Resources Board of the Oklahoma Department of Health protects all surface and ground waters to ensure that pollution does not occur and that discharges meet specified beneficial uses outlined in water quality standards. Oklahoma has not been delegated NPDES authority. However, discharges to water from oil and gas activities are not permitted. The Water Resources Board issues land application permits for reserve pit fluids.

The Osage Indian Tribe has sole primacy regarding oil and gas operations in Osage County and has been delegated UIC program responsibility for Class II wells.

The U.S. Bureau of Land Management has primacy where both surface and mineral rights are owned by the Bureau or by an Indian Tribe other than the Osage Tribe. In those cases where mineral rights are owned by the Bureau or an Indian Tribe, but not the surface rights, both the Bureau and the Oklahoma Corporation Commission would become involved and would coordinate the permitting procedures.

STATE RULES AND REGULATIONS

DRILLING

Corporation Commission Rule 3-104 specifies that pits and tanks for drilling mud or deleterious substances used in the drilling, completion, and recompletion of wells shall be constructed and maintained to prevent pollution of surface and subsurface fresh water. A written permit is issued for the use of an onsite earthen pit (Rule 3-110.1). Any reserve mud pit used in drilling, deepening, testing, reworking, or plugging a well must be emptied and leveled within a maximum of 18 months after the drilling operations cease (Rule 3-110.1(d)(2)).

Reserve drilling pit fluids are permitted on a one-time basis by the Water Resources Board to be spray-applied to land as a part of pit closure providing certain limits are met. These limits include a pH range of 6.5 to 9.0 and not to exceed:

Chlorides	1,000	mg/l
Total chromium	0.2	mg/l
Chemical oxygen demand	250	mg/l
Total dissolved solids	3,000	mg/l
Oil and grease	30	mg/l
Total sodium	750	mg/l
Specific conductance	4,600	u mhos

Special field rules have been adopted that prohibit the use of pits in certain areas. This has caused the use of offsite reserve pits for a particular well.

Drilling fluid must be disposed of by one of three ways: Annular injection, evaporation then closure of a reserve pit, or vacuum truck removal to offsite earthen pits. A manifest is required for offsite transportation. High chloride content drilling fluids are injected into a Class II well.

PRODUCTION

Underground disposal of high chloride produced water is required either in disposal wells or enhanced recovery injection wells. There are about 5,200 of the former and 9,900 of the latter. The Oil and Gas Commission has been delegated UIC program activities for Class II wells.

OFFSITE AND COMMERCIAL PITS

Rule 3-110.2 of the Oklahoma Corporation Commission permits the use of offsite earthen pits provided they are sealed with an impervious material, do not receive outside runoff water, and are filled and leveled within 1 year after abandonment. The chloride content of the contained fluids shall not exceed 3,500 mg/l. Drilling muds containing both solids and fluids may be transported to such commercial pits.

Offsite pits are created by excavating, damming gullies, and using abandoned strip pits. There are approximately 95 offsite pits throughout Oklahoma, ranging as large as 15 acres. They are sampled periodically to enforce a maximum 3,500 parts per million chloride concentration requirement. If the pit bottom mud cannot meet chloride limits, it must be effectively treated and hauled to a hazardous waste disposal site. Some offsite pits are large and may contain over 3,000,000 barrels of waste, which calculates to 387 acre feet of fluids.

Owners of new pits are required to install and sample monitoring wells, principally for chlorides and pH. There is a proposal, currently, to made such requirement applicable to existing offsite pits. Three wells would be required--one upgradient and two downgradient. Any indicated change over background in the constituent levels tested would indicate potential pollution.

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The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

General Rules and Regulations of the Oil and Gas Conservation Division, The Corporation Commission of the State of Oklahoma (1986).

Oklahoma Drilling Waste Conference.

Personal Communications:

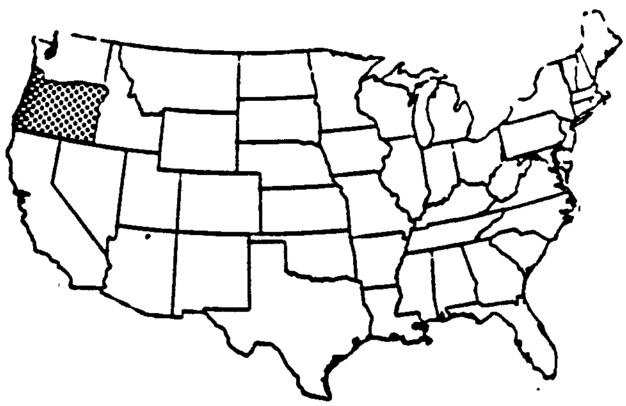
Mike Battles, Manager of Pollution Abatement, Oklahoma Corporation Commission (405) 521-4456

Karen Dihrberg, Geologist, Water Resources Board (405) 271-2549.

Margaret Graham, Permits, Water Resources Board (405) 271-2561.

OREGON

INTRODUCTION



Oregon does not produce oil. Oregon's only producing gas field was discovered in 1979. Eleven active gas wells produced 2.8 x 10^9 cubic feet of gas in 1984. There are four additional wells that are capable of production but currently these are not producing wells. There is one saltwater injection well for the field. In 1984, approximately 100,000 barrels of brine were injected underground; about 19,000 barrels went to surface land disposal.

STATE REGULATORY AGENCIES

Two agencies regulate oil and gas activity in Oregon:

- Oregon Department of Geology and Mineral Industries
- Oregon Department of Environmental Quality

Oil and gas drilling permits are issued by the Oregon Department of Geology and Mineral Industries. The State Geologist serves as the implementor of rules, orders, and enforcement actions taken by the Department's governing board.

The Oregon Department of Environmental Quality has delegated authority for the NPDES program and issues UIC permits. The State has maintained a permitting program since 1968. No NPDES permits have been issued because there have been no requests to discharge waste to public waters.

None of the gas wells is on Federal lands. All are located where Columbia County owns the mineral rights. If, in the future, drilling were to take place on Federal lands, there would be two separate permitting actions--one by the U.S. Bureau of Land Management and one by the Oregon Department of Geology and Mineral Industries.

STATE RULES AND REGULATIONS

DRILLING

Oregon Administrative Rule 632-10-205 requires a surety bond of up to $25,000 for one well, or a blanket bond of $150,000 for more than one well, conditioned upon the faithful compliance by the principal with the rules, regulations, and orders of the Department of Geology and Mineral Industries.

Rule 632-10-140 requires that any fluid necessary to the drilling, production, or other operations by the permittee shall be discharged or placed in pits and sumps approved by the State Geologist and the State Department of Environmental Quality. The operator shall provide pits, sumps, or tanks of adequate capacity and design to retain all materials. In no event shall the contents of a pit or sump be allowed to:

1. Contaminate streams, artificial canals or waterways, groundwaters, lakes, or rivers.
2. Adversely affect the environment, persons, plants, fish, and wildlife and their population.

When no longer needed, fluid in pits and sumps is to be disposed of in a manner approved by the Department of Environmental Quality and the sumps filled and covered and the premises restored to a near natural state. The restoration need not be done if arrangements are made with the surface owner to leave the site suitable for beneficial subsequent use.

Drilling mud pits are not allowed to hold over winter because of lack of sufficient storage for winter rainfall. If drilling muds dry in the reserve pits before winter occurs, the pit is then closed.

There has not been a problem with abandoned pits; the surety bond provides a mechanism to ensure adequate pit closure.

PRODUCTION

Rule 632-10-192 of the Department of Geology and Mineral Industries provides that brines or saltwater liquids may be:

1. Disposed in pits only when the pit is lined with impervious material and a Water Pollution Control Facility permit has been issued by the Department of Environmental Quality. Earthen pits used for impounding brine or salt water shall be so constructed and maintained as to prevent the escape of fluid.

2. Disposed by injection into the strata from which produced or into other proved salt-water bearing strata.

3. Disposed by ocean discharge, which may be permitted if water quality is acceptable and if such discharge is approved by the State Department of Environmental Quality through issuance of a National Pollutant Discharge Elimination System waste discharge permit.

Produced brines are permitted to be spread on dirt roads--predominantly logging roads--when such is done in dry weather.

OFFSITE AND COMMERCIAL PITS

There are no operational offsite pits. One dump-site has been used as an emergency pit. Operators must dispose of drilling muds in a Department of Environmental Quality approved solid waste disposal site. Such solids may be tested prior to disposal to determine if they contain hazardous materials.

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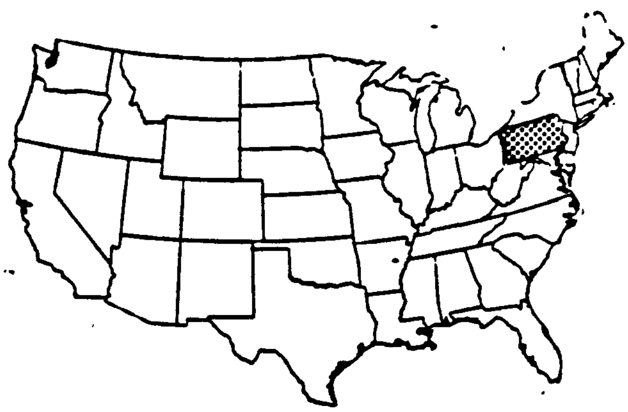
Personal Communications:

Dan Wermiol, Department of Geology and Mineral Industries (503) 229-5580.

Kent Ashbaker, Department of Environmental Quality (503) 229-5325.

PENNSYLVANIA

INTRODUCTION



Pennsylvania produced 4,825,000 barrels of oil and 166 x 10^9 cubic feet of gas in 1984. Production was from 20,739 oil wells and 24,050 gas wells.

Until 1955, environmental requirements for the oil and gas industry were minimal if not nonexistent. State laws did not require permitting or registration of oil and gas wells. In 1961, the statutes were strengthened to prohibit wasting in production wells, establish spacing, and provide other requirements. It was not until 1984 that the Coal and Resource Coordination Act and the Oil and Gas act made sweeping changes in permit review and requirements. There had been little uniformity in Pennsylvania oil and gas laws until then. Combined, these statutes enable Pennsylvania permitting authority to put terms and conditions on permits, and to deny permits. Passage of House Bill 1375 in mid-September, 1986, further strengthens the regulatory management of the oil and gas industry in Pennsylvania, and requires the development of new regulations relating to solid waste management and the disposal of wastes onsite.

The first commercial oil well was drilled near Titusville, PA, 1859.

STATE REGULATORY AGENCIES

Five agencies regulate oil and gas activities in Pennsylvania:

- Department of Environmental Resources, Bureau of Oil and Gas Management
- U.S. Environmental Protection Agency, Region III
- Pennsylvania Fish Commission
- U.S. Forest Service
- U.S. Bureau of Land Management

The Bureau of Oil and Gas Management was created in 1984 to coordinate and combine all related regulatory activities of the oil and gas industry. The Oil and Gas Conservation Law, enacted in 1961, established powers and duties of the Oil and Gas Conservation Commission. Those powers and duties were transferred to the Department of Environmental Resources in 1970. The Oil and Gas Act of 1984 created an Oil and Gas Technical Advisory Board to advise the Department in regulatory activities (Section 216 of 1984 Act). The five-member board consists of three representatives of the oil industry, one from the Citizen's Advisory Council, and one from the coal industry.

Section 207(a) of the Act requires that the disposal of drilling and production brines be consistent with the requirements of the Clean Streams Law. Section 208(a) requires that any well owner who affects the public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternative source. Section 205 prohibits drilling of wells within 200 feet of buildings or water wells without the consent of the owner, within 100 feet of any body of water, or within 100 feet of a wetland 1 acre or more in size.

There is a compliance bond conditioned on the operator's faithful performance of the drilling, restoration, water supply replacement, and well plugging requirements of the Oil and Gas Act. The passage of House Bill 1375 transferred NPDES permitting authority in the oil and gas industry--already delegated to the State--to the Bureau.

The U.S. Environmental Protection Agency, Region III, issues UIC program permits for underground injection and secondary recovery. The Bureau of Oil and Gas Management has not sought primacy in the UIC program.

The Pennsylvania Fish Commission seeks out pollution of surface waters and takes appropriate action under the Pennsylvania Fish and Boat Code.

The U.S. Forest Service and the U.S. Bureau of Land Management provide requirements they may have in lease agreements. The well driller must demonstrate his notification of landowners and water supply owners of the intent to drill. Mineral rights in the Allegheny National Forest are privately owned. The Bureau of Oil and Gas Management issues drilling permits on Federal lands.

STATE RULES AND REGULATIONS

DRILLING

Drilling pits to the present time have been virtually unregulated. Pits typically are unlined. Such pits contain drilling cuttings, contaminated fresh and salt water produced during construction and well stimulation, and various additives used during drilling and well stimulation. Pits are not reclaimed and no permit is required for a drill pit. There is no contingency fund for management of abandoned pits.

The Bureau is in the process of developing regulations to further control oil and gas operations. The thrust on drilling pits is to remove liquids to an offsite and commercial treatment and disposal facility and to dispose of solids waste on site with pit reclamation.

PRODUCTION

It has been estimated that Pennsylvania has 17,000 impoundments associated with oil and gas brines. If an impoundment is associated with an individual well, a permit has not been required. Permits are required for offsite and commercial treatment systems. The trend since 1985 has been to move in the direction of centralized treatment facilities for oil and gas waste fluids. It is estimated that currently 20 percent of all brines are transported to a treatment plant for treatment and discharge. No manifest is required for transporting oil and gas waste materials.

There are other production fluid disposal alternatives, which include:

- Disposal wells
- Annular disposal
- Treatment and discharge to surface waters
- Onsite treatment and land disposal of top hole water
- Discharge to existing treatment facility
- Road spreading
- Evaporation (through waste heat)

OFFSITE AND COMMERCIAL PITS

Water Quality Management Part II permits and NPDES permits are required for treatment facilities that discharge to waters of the Commonwealth. Treatment afforded production fluids may include flow equalization, pH adjustment, gravity separation and surface skimming, retention and settling and, if necessary, aeration. The discharges from several offside produced-fluids treatment facilities may be covered under a single NPDES permit, if the management of those facilities is under the control of one owner/operator and the geographic area is such as to allow for effective monitoring and surveillance.

The NPDES permit criteria and limits will be governed by receiving water quality standards. Generally, however, total suspended solids will be limited to an instantaneous maximum of 60 mg/l and an average monthly of 30 mg/l. Oil and grease will be limited to an instantaneous maximum of 30 mg/l and an average monthly of 15 mg/l. Dissolved iron has an instantaneous maximum of 7 mg/l, and the acidity shall be less than the alkalinity.

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The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

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Pennsylvania Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workshop. U.S. Environmental Protection Agency, Washington, D.C. (March 26-27 in Atlanta, GA).

The Oil and Gas Act, Act of 12-19-84, P.L. 1140, No. 223.

The Oil and Gas Conservation Law, 1961, P.O. 825, No. 359.

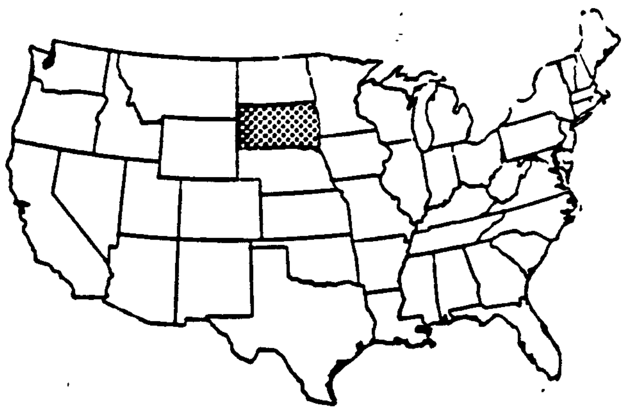
Rules and Regulations, Department of Environmental Resources, Chapter 97, Industrial Wastes.

Personal Communication:

Carlyle Westlund, Bureau of Oil and Gas Management (717) 783-9645.

SOUTH DAKOTA

INTRODUCTION



South Dakota produced 710,000 barrels of oil and 2.5×10^9 cubic feet of gas in 1984. The State has 312 full production and 33 stripper oil wells, and 41 full production and 1 marginal production gas wells.

STATE REGULATORY AGENCIES

Four agencies regulate oil and gas activities in South Dakota:

- South Dakota Department of Water and Natural Resources
- South Dakota Department of School and Public Lands
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency, Region VIII

The South Dakota Department of Water and Natural Resources is the primary regulatory agency for oil and gas operations through its Oil and Gas Program in the Division of Environmental Quality. The primary enforcement agency for the UIC program, and non-delegated responsibility for NPDES compliance, is the Department's Office of Water Quality. The Department of Water and Natural Resources also houses the Board of Minerals and Environment, which has power to conduct hearings and take action on other oil and gas program related enforcement measures.

South Dakota has not been delegated NPDES authority. Two of the active wells have NPDES permits because of beneficial use associated with wastewaters. Draft NPDES permits are prepared by the State and issued by the Water Management Division, U.S. Environmental Protection Agency, Region VIII.

In the event of a desire to drill on Federal lands, two applications for drilling would be filed--one with the State Department of Water and Natural Resources, and one with the U.S. Bureau of Land Management. The State would defer to the Bureau regarding any pre-drilling permit investigation. Two permits, one from each entity, would be issued to the driller. In the event of a request to inject drilling fluids underground, the Bureau would defer to the State, and the State would issue the injection permit. The Bureau has no means of holding hearings, and the State Board of Minerals and Environment would hold such hearings prior to permit issuance.

The South Dakota Department of School and Public Lands has enforcement powers for lease compliance on State-owned lands and for State-owned minerals.

STATE RULES AND REGULATIONS

DRILLING

Total retention evaporation ponds for brines, underground injection wells for brines and drilling muds, and burial of drilling muds are allowed. There are no specific requirements related to pit construction.

Drilling pits may become a source of groundwater pollution, depending upon local hydrologic conditions. There has been a documented complaint of contamination from salt brines in an unlined pit where groundwater was used for stock watering. This complaint currently is in the negotiation phase. Currently, also, the State is undertaking regulation revision, and consideration is being given to a proposal to require that pits have liners or be of impermeable construction.

When drilling operations cease, water in the pit is allowed to evaporate and the mud is allowed to dry. The time interval for this to occur is a various and unknown factor. When the mud has sufficiently dried, the pit is buried and the surface is reclaimed to natural conditions.

The Department of Water and Natural Resources requires a Plugging and Performance Bond for wells, and a Surface Restoration Bond. There is a well spacing requirement.

PRODUCTION

Discharge of brine from oil well production is allowed when a beneficial use of the wastewater can be documented. An NPDES permit is required for such discharge. The two NPDES permitted discharges from wells in South Dakota are used for stock watering. NPDES permits contain not-to-exceed limits for oil and grease of 10 mg/l, total dissolved solids of 5,000 mg/l, and a pH of 6.0 to 9.0. The flow is not to exceed 4,500 gallons per day.

OFFSITE AND COMMERCIAL PITS

There are no offsite pits in use, but if there were a request for such usage, the request would be managed through the solid waste permitting process.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Pirner, S. M. 1986. Letter Communication to EPA. South Dakota Department of Water and Natural Resources, Office of Water Quality.

Personal Communications:

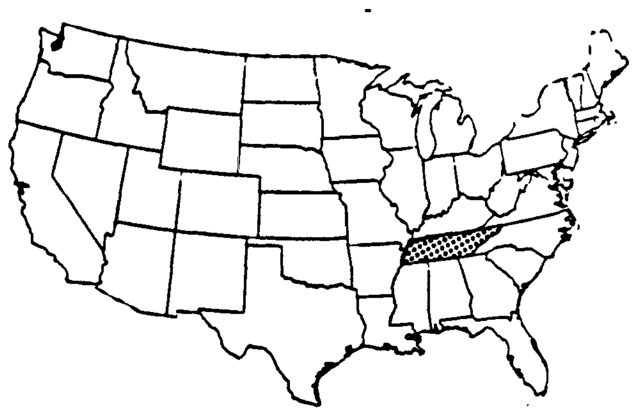
Steven M. Pirner, DWNR, Office of Water Quality (605) 773-3351.

Fred V. Steece, DWNR, Supervisor of Oil and Gas Program (605) 394-2385.

TENNESSEE

INTRODUCTION

Tennessee produced about 937,000 barrels of oil from 798 wells in 1984. Only 54 oil wells produced more than 10 barrels of oil per day. Of 507 gas wells, 474 produce less than 60 thousand cubic feet per day.



Regulation of oil and gas drilling operations began in 1968. Wells drilled prior to 1968 do not have to be permitted unless they are deepened, reopened, or reentered.

STATE REGULATORY AGENCIES

Three agencies regulate oil and gas activities in Tennessee:

- State Oil and Gas Board
- Tennessee Department of Health and Environment
- U.S. Department of the Interior, Bureau of Land Management

The State Oil and Gas Board is authorized by the Tennessee Code Annotated (Revised 1982) for prevention of waste of petroleum resources in Tennessee. The State Oil and Gas Board regulates the industry according to the General Rules and Regulations (Tennessee State Oil and Gas Board Statewide Order No. 2). The State Oil and Gas Board issues drilling permits and regulates surface disposal.

The Department of Health and Environment is the NPDES authority in Tennessee. They do not currently have UIC primacy, but are working towards being granted primacy by EPA. Discharges of oil and gas wastes are not permitted by the Tennessee Department of Health and Environment.

The U.S. Department of the Interior Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service.

RULES AND REGULATIONS

DRILLING

The State Oil and Gas General Rules and Regulations are directed towards prevention of waste. The rules do not address drill pit construction, use, or closure requirements. The Oil and Gas Board has been working to develop rules with regard to waste pits, and plans to incorporate them into its rules and regulations. The Oil and Gas Board has instituted a policy requiring that proposed well sites "be inspected with regard to its waste pits, and that those pits be approved by the gas and oil field inspector assigned to that particular well prior to the issuance of a drilling permit for that well."

The State Oil and Gas Board regulates spacing, casing, plugging, and abandonment of wells.

PRODUCTION

"Produced water and plant wastes may be disposed of into subsurface formations not productive of hydrocarbons, groundwater, or other mineral resources." It is also considered acceptable for produced water to be disposed in evaporation pits approved by the State Oil and Gas Board Supervisor. Criteria for approval are not part of the rules.

The State Oil and Gas Board Assistant Supervisor maintains that Tennessee gas wells and oil wells producing over 10 barrels of oil per day do not produce salt water. The Assistant Supervisor estimates "Statewide average daily production of slightly more than 0.1 barrels of water per day [per full producing oil well]."

OFFSITE PITS

The regulations do not specifically address offsite pits.

REFERENCES

Zurawski, Ronald P. "1985 EPA Onshore Oil and Gas Workshop Request for Information on Tennessee Activity and Technology," circa mid-1985.

State of Tennessee - State Oil and Gas Board. "General Rules and Regulations, Statewide Order No. 2," Effective November 1972.

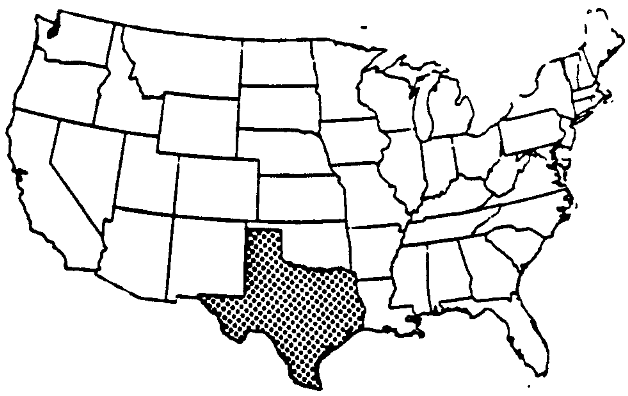
Zurawski, Ronald P. Drilling Waste Conference submittal, circa mid-1985.

State of Tennessee State Oil and Gas Board. "Oil and Gas Laws in Tennessee and Mineral Test Hole Regulatory Act," Amendments added 1982.

TEXAS

INTRODUCTION

Texas produces 856 million barrels of oil annually from over 200,000 wells. Gas production is 6,753,889 MMCF from 43,174 gas wells. It is estimated that 75 percent of all active Texas wells are marginally-producing wells.



Regulation of the oil and gas industry began in Texas when the Railroad Commission was assigned jurisdiction over oil and gas activities in 1919.

STATE REGULATORY AGENCIES

Five agencies have jurisdiction over disposal of oil and gas wastes in Texas:

- Railroad Commission of Texas
- Texas Water Commission
- Texas Parks and Wildlife Department
- U.S. Bureau of Land Management (and the Bureau of Indian Affairs)
- U.S. Corps of Engineers

Oil and gas activities in Texas are regulated almost entirely by the Railroad Commission of Texas. Unlike many State oil and gas commissions, the Railroad Commission is responsible for both prevention of waste and for prevention of pollution. Thus one agency is responsible for well spacing, construction requirements (casing, etc.), and environmental protection (air, water, etc.).

According to the Texas Administrative Code, Title 31 as amended July 3, 1986, the Texas Water Commission jurisdiction over disposal activities is superceded by Railroad Commission and Department of Health authority.

The Texas Parks and Wildlife Department, Pollution Surveillance Branch, investigates fish kills and water pollution complaints and evaluates the effects of discharged wastes on fish and wildlife. The Texas Parks and Wildlife Department has statutory authority to recover the monetary value of damaged fish and wildlife. The Parks and Wildlife Department may also enforce the Texas Water Code when permit violations, discharges in excess of permit limitations, or discharges without a permit occur.

The U.S. Department of the Interior, Bureau of Land Management, has jurisdiction over lease arrangements and post-lease activity on Federal lands. Their rules are discussed in a separate section, Federal Agencies. The Bureau of Indian Affairs has some jurisdiction in limited areas of Texas.

STATE RULES AND REGULATIONS

GENERAL

Texas State Rule 8 prohibits any "person conducting activities subject to regulation by the state" from causing or allowing pollution of surface or subsurface waters in Texas. Except for underground injection (either for disposal or for enhanced recovery), "no person may dispose of any oil and gas wastes by any method without obtaining a permit to dispose of such wastes."

DRILLING

The Railroad Commission of Texas has the authority to permit reserve pits, mud circulation pits, completion/workover pits, basic sediment pits, flare pits, fresh makeup water pits, and water condensate pits. The use of mud pits and mud recirculation pits for oil and gas wastes is limited to drilling fluids, drill cuttings, wash water, drill stem test fluids, and blowout preventer test fluids. Pit locations are evaluated on a case-by-case basis to determine what construction requirements are necessary to prevent waste of oil and gas resources or pollution of surface water, groundwater, or agricultural land. The requirements may or may not include liners.

Permits must carry requirements for pit operation (maintenance) and pit closure as well. The Railroad Commission requires that pits be dewatered, backfilled, and compacted for closure. Backfill requirements (for all type of pits) vary according to the type of pit and the chloride concentration of the pit contents. Reserve pits (and mud recirculation pits) containing over 6,100 mg/l chloride must be dewatered within 30 days and backfilled within one year of cessation of drilling operations. The operator has up to one year to dewater and to backfill reserve pits (and mud circulation pits) containing less than 6,100 mg/l chlorides.

Completion and workover pits must be dewatered within 30 days and compacted within 120 days of completion of workover operations. Basic sediment pits must be closed "within 120 days of cessation of use of the pits."

Pit fluids and other oil and gas wastes are tracked via a manifest system in Texas. Railroad Commission permits are necessary to "transport, store, handle, treat, reclaim, or dispose of oil and gas wastes."

The Railroad Commission permits treatment and discharge of reserve pit fluids to land or to surface waters provided that the discharge does not cause a violation of Texas water quality standards. The rule is unclear as to what processes constitute acceptable treatment technologies. The permit "does not authorize the use of surfactants or spray adjuvants." The criteria for discharges to surface waters are:

- 24-hour bioassay by Texas Parks and Wildlife
- Chemical oxygen demand $\leq$ 200 mg/l
- Total suspended solids $\leq$ 50 mg/l
- Total dissolved solids $\leq$ 3000 m/l
- Oil and grease $\leq$ 15 mg/l
- Chlorides (coastal) $\leq$ 1000 mg/l
- Chlorides (inland) $\leq$ 500 mg/l
- pH 6.0 to 9.0
- Water color must be adjusted to match the receiving stream
- Volume of the discharge must be "controlled so that a minimum 5:1 dilution of the wastewater by the principal receiving stream is maintained."
- Discharge cannot exceed concentrations of hazardous metals as defined by Texas Water Development Board Rules 156.19.15.001-.009.

No permit is required for landfarming of water-based drilling fluids and associated wastes with a concentration of chlorides at or below 3000 mg/l; however, the written consent of the landowner must be obtained. Landfarming encompasses sprinkler irrigation, trenching, injecting under the surface using a disc, and surface spreading by vehicles as defined by the Railroad Commission of Texas. Applications for discharge permits do not require submittal of analytical data on wastes.

Annular injection of drilling fluids is also regulated via "minor permits" issued by the Railroad Commission of Texas. Certain conditions and limitations apply to the use annular injection for disposal.

Drilling is allowed in wildlife management areas and in State parks. Drilling muds are often disposed on State property.

On Federal lands, the Railroad Commission of Texas has jurisdiction whenever mineral rights are privately owned, although the U.S Forest Service retains surface rights. For Federally-owned mineral rights, the Bureau of Land Management has jurisdiction.

PRODUCTION

Injection of produced water is the major approved disposal method for brine. "Texas has primacy for Class II wells and has permitted approximately 47,000 such wells."

The Railroad Commission allows discharge of produced water into coastal areas on an individual basis. The application for a discharge permit does not require submittal of analytical data for produced water.

West of the 98th meridian, the Railroad Commission permits "beneficial use" of produced waters where there will be no discharge.

OFFSITE PITS

Although there are currently about 200 saltwater disposal pits operating in Texas, these pits are not specifically addressed in Texas Railroad Commission rules and regulations.

REFERENCES

Railroad Commission of Texas, Oil and Gas Division. Rules Having Statewide Application to Oil Gas and Geothermal Resource Operations Within the State of Texas, September 1985.

Interstate Oil Compact Commission, The Oil and Gas Compact Bulletin, Volume XLIV, Number 2, December 1985.

Railroad Commission of Texas, Oil and Gas Division. Water Protection Manual, April 1985.

U.S. Environmental Protection Agency, Proceedings - Onshore Oil and Gas State/Federal Western Workshop, December 1985.

"Texas Surface Water Quality Standards," TDWR Publication LP-71.

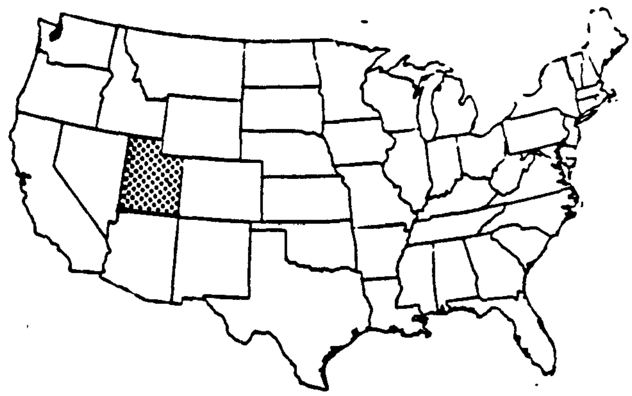
Railroad Commission of Texas, "Application Information - Casing/Annulus Disposal of Drilling Fluid." Not dated.

Railroad Commission of Texas, Letter communication to EPA, October 1985.

UTAH

INTRODUCTION

Utah produced 35,750 barrels of oil annually from 1,862 wells in 1984. Approximately 20 percent of these oil wells are strippers. Utah's gas fields produced 99.8 x 10^9 cubic feet of gas from 728 gas wells in 1984. It is not known what proportion of these wells are marginal producers of gas.



STATE REGULATORY AGENCIES

Four agencies share regulatory responsibility for oil and gas activities in Utah:

- Utah Department of Natural Resources, Division of Oil, Gas, and Mining
- Department of Health, Bureau of Water Pollution Control
- U.S. Bureau of Land Management (and possibly the Bureau of Indian Affairs)
- U.S. Forest Service (surface rights only)

The Division of Oil, Gas, and Mining adopted new Oil and Gas Conservation General Rules effective December 2, 1985. These rules cover drilling and operating practices, UIC Class II responsibility, and rules governing purchasing, transportation, refining, and rerefining. The Department of Health currently has regulatory authority over disposal ponds. The Department of Oil, Gas, and Mining is hoping to bring most aspects of oil and gas regulations under one agency by assuming authority for disposal ponds in the near future.

The U.S. Department of the Interior, Bureau of Land Management, has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service.

STATE RULES AND REGULATIONS

DRILLING

Rule 308 of the Division of Oil, Gas, and Mining rules requires oil and gas operators to "take all reasonable precautions to avoid polluting streams, reservoirs, natural drainage ways, and underground water." This requirement is supported by a specific rule for reserve pits (Rule 309). "Salt water and oil field wastes associated with the drilling process may be impounded in excavated earthen reserve pits underlain by tight soil such as heavy clay or hardpan or lined in a manner acceptable to the Division." Pit liquids are not allowed to escape onto the land surface or into surface waters.

Since most of Utah has very rapid evaporation rates, the reserve pit supernatant is generally allowed to evaporate before pit closure. Final pit closure requirements were not found in the rules.

In areas of net precipitation, or in areas where pit construction is especially difficult (i.e., steep mountain sides), the Division may allow the reserve pit supernatant to be disposed down the annulus of the new well into a properly confined zone of poor water quality. This determination is made by the Division of Oil, Gas, and Mining on a case-by-case basis.

The Division of Oil, Gas, and Mining has extensive technical rules regarding well siting, casing requirements, and well drilling.

PRODUCTION

Most produced water is injected for water flooding or for disposal. Utah has approximately 560 Class II injection wells, including about 45 disposal wells. The Division of Oil, Gas, and Mining controls injection wells and onsite disposal facilities.*

The Utah Department of Health regulates surface disposal of produced water from gas and oil wells. No pond is allowed to discharge to the surface (land or water). Construction requirements seek to protect the pit from intrusion of surface water, be constructed of impervious material, and be located at

* "Onsite disposal facilities" are presumed to include onsite evaporation pits. The Division of Oil, Gas, and Mining rules do not include specific guidance regarding onsite disposal facilities, however, their reserve pit guidance is probably applied to produced water pits as well. There appears to be some overlap in authority for onsite pits between the Utah Department of Health and the Division of Oil, Gas, and Mining.

least 5 feet above groundwater. Pits must be properly located above ordinary high water marks for surface waters. Pits may not be located within 200 feet of a fault or at the bottom of creeks, rivers, or natural drainages.

Surface disposal into unlined ponds is allowed if the wastewater contains less than 5,000 mg/l total dissolved solids, and if the wastewater does not contain "objectionable or toxic levels of any constituent as shown by chemical analyses." This requirement is waived for sites discharging less than 5 barrels of water per day. Small dischargers into unlined pits are required only to notify the Department of Health with minimal site information. Application for approval to discharge into unlined pits must include an estimate of waste volume, estimate of percolation and net evaporation rates, and information about freshwater aquifers within a one square mile radius of the proposed site.

For disposal ponds without artificial liners which receive more than 100 barrels per day, the Department of Health requires a monitoring program including monitoring wells.

For artificially-lined ponds, the Department of Health requires "an underlying gravel-filled sump and lateral system, or other suitable devices for detection of leaks." The Department of Health, Bureau of Water Pollution Control, is considering a requirement that all ponds (lined or unlined) be equipped with a leak detection system. In general, the Bureau feels that pit siting is more important than construction requirements.

REFERENCES

Interstate Oil Compact Commission, The Oil and Gas Compact Bulletin, Volume XLIV, Number 2, December 1985.

U. S. Environmental Protection Agency, Proceedings - Onshore Oil and Gas State/Federal Western Workshop, December 1985.

Hunt, Gil. Letter to Ms. Susan de Nagy with attachments dated September 20, 1985.

Swindel, D. B. Letter to Kerri Kennedy with attachments dated June 6, 1986.

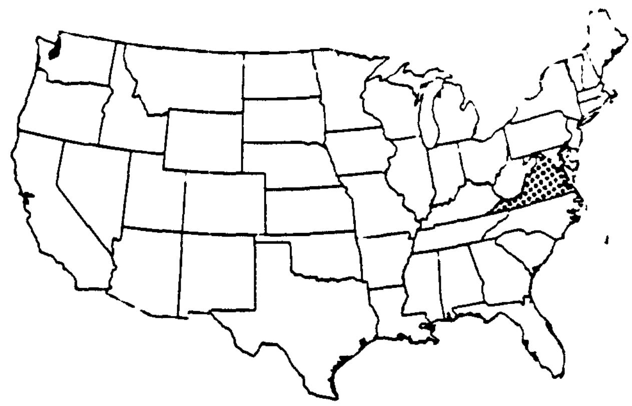
"The Oil and Gas Commission General Rules," effective December 2, 1985.

Utah Water Pollution Control Committee, State of Utah, Department of Health, Division of Environmental Health, Wastewater Disposal Regulations -- Part VI Surface Disposal of Produced Water from Gas and Oil Wells, January 20, 1982.

VIRGINIA

INTRODUCTION

Virginia produced 33,000 barrels of oil from 35 producing oil wells and 9 x 10^9 cubic feet of gas from 499 gas wells in 1984.



STATE REGULATORY AGENCY

One agency principally regulates oil and gas activities in Virginia:

- Virginia Department of Mines, Minerals, and Energy, Oil and Gas Section

The Oil and Gas Section is governed by the Virginia Oil and Gas Act and by the Rules and Regulations for Conservation of Oil and Gas Resources and Well Spacing as issued by the Virginia Department of Labor and Industry. The Oil and Gas Section issues drilling permits and regulates the details of the industry through this process. The State does not have primacy for the UIC program Class II wells, but there is no underground injection of fluids currently associated with the Virginia industry. There has been drilling on Federal lands, but such lands are owned by the National Forest Service and the Service serves as another surface landowner in such drilling activity. The Service would manage their concerns principally through the surface lease process. The Virginia Water Control Board would become involved only in the event of an incident that potentially could affect surface water quality.

STATE RULES AND REGULATIONS

DRILLING

Virginia Regulations 3.02 (f) and (g) require pits to be associated with the drilling of a well that will preclude water pollution. Pits must be lined with a plastic liner, and the drill site and any associated pits must be reclaimed within 1 year after drilling ceases.

In general, there is little fluid associated with the drilling process in Virginia. Such fluids as may be present are not high in chloride concentration. Generally, the fluid is tested by the driller, the pH is adjusted if necessary, and the water is sprayed on the surrounding land. Pit muds are buried on site and the pit area reclaimed.

PRODUCTION

Almost no fluid is associated with gas production in Virginia. Very small amounts of fluids are produced with the 100 gallons of oil produced per day statewide. As a result, produced waters generally are held in steel tanks. Dikes are required around the tanks, and fluids generally are allowed to flow into the diked area, where they disappear through evaporation and infiltration.

OFFSITE AND COMMERCIAL PITS

No use is made of offsite and commercial pits in Virginia.

REFERENCES

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (June).

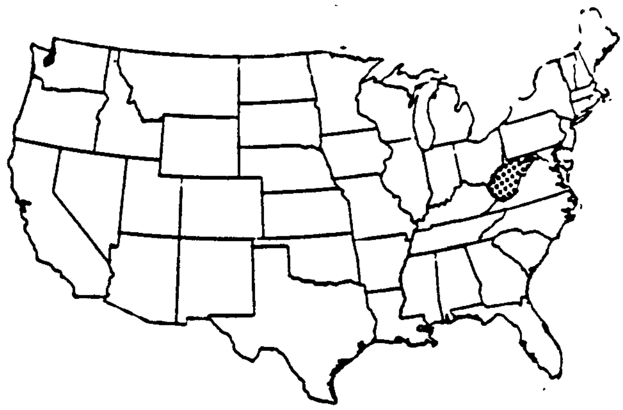
Personal Communication:

James Henderson, State Oil and Gas Inspector (703) 628-8115.

WEST VIRGINIA

INTRODUCTION

West Virginia produces about four million barrels of oil per year from 15,475 wells. Gas production of 136 billion cubic feet annually is realized from 30,700 wells. Between 1,800 and 2,500 drilling permits are issued annually, although the number of wells drilled has dropped in 1986.



STATE REGULATORY AGENCIES

Two agencies regulate oil and gas acstivities in West Virginia:

- West Virginia Department of Energy
- U.S. Bureau of Land Management

The recently-created West Virginia Department of Energy has statutory authority over oil and gas activities in the State. The Department of Energy is in the process of assuming responsibilities from the Department of Mines, Office of Oil and Gas (historically the drilling permitting authority), and from the Department of Natural Resources, Water Resources Division and Reclamation Division. West Virginia has proposed regulations and hearings have been conducted regarding the oil and gas industry. However, new regulations cannot go into effect until the State legislature approves them and the Governor signs a proclamation. Thus, old regulations remain in place. In the interim, the Department of Natural Resources and Department of Mines are working cooperatively with the Department of Energy towards a transition of responsibilities.

The current reorganization seriously complicates a presentation of existing regulations. For instance, the Department of Natural Resources, Water Resources Division, retains NPDES delegation, although the Department of Energy has applied for delegation specifically limited to oil and gas wastes and certain other industries. This parallel permitting responsibility is duplicated for other regulatory areas as well.

The U.S. of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands. Their rules are discussed in a separate section, Federal Agencies. The U.S. Forest Service retains surface rights on Federal forests and grasslands. They coordinate surface stipulations with the Bureau of Land Management where applicable.

STATE RULES AND REGULATIONS

The following discussion of State rules and regulations is based on proposed rules and regulations that are expected to become effective in early 1987. Current copies of the proposed rules stress an outline of the authority and definitions of responsibilities rather than specific waste handling regulations.

DRILLING

The Department of Energy issues drilling permits for all oil and gas wells in the State. Suitable applications must provide detailed information regarding locale, site, and construction plans. The Department of Energy has well construction requirements which include casing, cement type, or cement strength. Permitted drillers are required to keep work records during the period of work. Similar information is required for applications for plugging and abandonment.

PRODUCTION

The West Virginia Department of Energy is applying for NPDES delegation for discharges from oil and gas operations. The regulations are closely modeled after 40 CFR 124.

REFERENCES

Interstate Oil and Gas Compact Commission, The Oil and Gas Compact Bulletin, Volume XLIV, Number 2, December 1985.

Personal communication with Mr. Ted Streit, former head of Office of Oil and Gas. September 25, 1986.

West Virginia Department of Energy, "Notice of Public Hearing and Comment Period on Proposed Rules," not dated. Received October 1986.

Streit, T. M. Letter submitted to William A. Telliard, U. S. EPA, May 28, 1985.

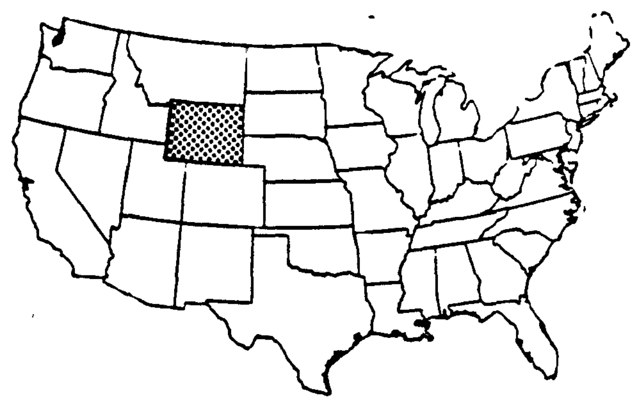
West Virginia Legislative Rule Department of Energy - Division of Oil and Gas Chapters 22-1 and 22B-1 Series 2.

West Virginia Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workshop. U.S. EPA, Washington, D.C. (March 26-27 in Atlanta, GA).

WYOMING

INTRODUCTION

Wyoming produced 127,763,000 barrels of oil and 600,137 million cubic feet of gas in 1984. Production is from 12,463 oil wells and 2,280 gas wells. Although many of these wells had been producing for 30 to 40 years, discharges of produced water were not permitted until the Clean Water Act was passed in 1972.



STATE REGULATORY AGENCIES

Three agencies regulate oil and gas activity in Wyoming:

- Wyoming Department of Environmental Quality
- Wyoming Oil and Gas Conservation Commission
- U.S. Department of Interior, Bureau of Land Management

The Wyoming Oil and Gas Conservation Commission has the authority to "monitor and regulate, by the promulgation of rules and the issuance of orders, the location, operation, and reclamation of produced water and emergency overflow pits associated with oil and gas production." The Commission regulates industry practices and procedures with regard to construction, location, and operation of onsite drilling and onsite production pits which serve a single well. The Oil and Gas Conservation Commission is chaired by the Governor of Wyoming, and four other commissioners. The Office of the State Oil and Gas Supervisor is primarily responsible for regulation of industry practices as described above.

Wyoming is an NPDES-delegated State. The Wyoming Department of Environmental Quality has NPDES authority for all discharges. Department of Environmental Quality has "jurisdiction and authority to regulate through monitoring and the promulgation of rules, regulations and orders governing treatment works and disposal systems and other facilities capable of causing or contributing to pollution, pursuant to W.S. 35-11-301." These responsibilities generally cover offsite commercial ponds and disposal pits serving two or more wells. The Department of Environmental Quality also has permitting authority for land application or discharge of drilling wastes.

The cooperative roles between the Wyoming Oil and Gas Commission and the Department of Environmental Quality is described in "Memorandum of Agreement between the Wyoming Oil and Gas Conservation Commission and the Department of Environmental Quality," dated September 13, 1983, and in the memorandum from the Wyoming Attorney General's office to the Office of the State Oil and Gas Supervisor dated January 18, 1982.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. For drilling on Federal land, the U.S. Bureau of Land Management handles all Applications to Drill. The Bureau requires extensive environmental documentation, including environmental assessments and develops environmental impact statements for drilling on Federal land. For produced water, the Bureau routinely approves discharges of produced water up to 5 barrels per day under Notice to Lessees 2B.

STATE RULES AND REGULATIONS

DRILLING

Section 326 of the Rules and Regulations of the Wyoming Oil and Gas Conservation Commission states, "At no time will drilling fluids be discharged into live waters or into any drainages that lead to live waters of the state." Application forms for temporary earthen pits (including reserve pits) allow only one of three designations for final disposition of pit contents: evaporation, hauling, or injection in a disposal well. No manifest system is in effect for hauled wastes.

Earthen pits are required to be constructed to "prevent pollution of streams, underground water, or to unreasonably damage the surface of leased premises or other lands." The rules do not require pit or pond liners, leak detection, or other modifications to a simple earthen pit except where "potential for communication between the pit contents and surface water or shallow ground water is high." The State Supervisor makes this determination based on the information presented in the permit application (Form 14A or 14B).

The Department of Environmental Quality allows discharge of drilling fluids from pits associated with the drilling of oil and/or gas wells under exceptional conditions, including a "complete analysis of the drilling liquid, the volume of liquid to be discharged, the location of the proposed discharge, and the name of the receiving water," have been submitted to Department of Environmental Quality. These requirements must meet the approval of the Department of Environmental Quality and the landowner prior to discharge. (Wyoming Department of Environmental Quality Water Quality Rules and Regulations Chapter VII, p.5)

Workover and completion pits are exempted from permit requirements if their use is limited to containment of oil/water. No definition of oil/water is found in the rules; however, the Commission staff explains that these pits are not allowed to contain acids or other chemical fluids. Fresh and potable water are defined as (1) having TDS less than 10,000 milligrams per liter, (2) reasonably suited for domestic, agricultural, or livestock use, and (3) suitable for fish or aquatic life. State law adopts these limitations at the guidance of the Federal UIC program.

Chemical use which destroys, removes, or reduces the fluid seal of a reserve pit is prohibited. Chemical or mechanical treatment of reserve pits must be specially allowed after a public hearing before the Oil and Gas Commission.

Earthen pits must be reclaimed within 1 year of the date of last use unless the Supervisor grants a specific variance. Bonds guaranteeing pit reclamation are not released until the Commission has inspected and approved the reclaimed pit.

PRODUCTION

The Oil and Gas Commission requires permits for brine pits receiving more that 5 barrels of water per day. Pits receiving less than 5 barrels of water per day (i.e., less than 76,650 gallons per year) are unregulated. Even for larger pits, liners are required only in special cases where "potential for communication between the pit contents and surface water or shallow ground water is high."

The Wyoming Department of Environmental Quality's Water Quality Rules and Regulations, Chapter VII, describes the rules for surface discharge of water associated with the production of oil and gas. Discharge of produced water may be permitted by the Department of Environmental Quality if certain effluent limitations are met (including 2000 mg/l chlorides, 3000 mg/l sulfates, 5000 mg/l TDS, pH between 6.5 and 8.5, 10 mg/l oil and grease, toxic substances, and other reserved additional limitations). This discharge is permitted through the NPDES system. Exceptions to the foregoing limitations may be granted if "beneficial use" can be properly demonstrated to the Department of Environmental Quality, and unless the landowner or the Department of Environmental Quality determines that environmental damage would result.

OFFSITE AND COMMERCIAL PITS

The Department of Environmental Quality regulates offsite and commercial pits. Chapter III of the Wyoming Water Quality Rules and Regulations outlines three basic requirements for permitting commercial pits. First, the facility must demonstrate that its construction will not allow a discharge to groundwater by direct or indirect discharge, percolation, or filtration. Second, the quality of wastewater will not cause violation of any groundwater standards. Finally, that existing geology will not allow a discharge to groundwater.

REFERENCES

Personal communication with Ms. Janie Nelson, Wyoming Oil and Gas Commission, August 14, 1986. Telephone (307) 234-7147.

Personal communication with Mr. E. J. Fanning, Department of Environmental Quality, Water Quality Division, August 11 and August 14, 1986. Telephone (307) 777-7781.

Wyoming Department of Environmental Quality Water Quality Rules and Regulations, Chapter III, VII, IX, September 5, 1978.

SUMMARY OF FEDERAL REGULATIONS

U.S. FOREST SERVICE

National Forest Systems, which include National forests and National grasslands, are administered by the U.S. Forest Service within the U.S. Department of Agriculture. Every application to drill for oil and gas that impacts the above lands is reviewed by the Service.

Where a road use permit is required, or where permit conditions related to oil and gas drilling are appropriate, such are conveyed by interagency communication to the Bureau of Land Management. The Bureau issues the lease conditions at the request of the U.S. Forest Service.

The nature of any lease condition depends upon case-by-case site specific requirements.

Communication:

Craig Losche, U.S. Forest Service (703) 235-9873

BUREAU OF LAND MANAGEMENT

INTRODUCTION

Exploration, development, drilling, and production of onshore oil and gas on Federal and Indian lands are regulated separately from non-Federal lands. This separation of authority is significant for western States where oil and gas activity on Federal and Indian lands is a large proportion of statewide activity.

REGULATORY AGENCIES

The U.S. Department of the Interior is authorized by 30 CFR 221.4 and 221.32 for regulation of onshore oil and gas practices on Federal and Indian lands. The Department of Interior administers their regulatory program through state Bureau of Land Management or U.S. Geological Survey District offices. These agencies generally have procedures in place for coordination with state agencies on regulatory requirements. Where written agreements are not in place, the Bureau of Land Management usually works cooperatively with the respective state agencies.

The Bureau works closely with the U.S. Forest Service for surface stipulations in Federal forests or Federal grasslands. This arrangement is also provided for in the Federal regulations.

RULES AND REGULATIONS

The Bureau of Land Management has authority over all aspects of oil and gas activities on Federal lands. The authority includes leasing, bonding, and royalty arrangements, construction and well spacing requirements, waste handling, waste disposal, site reclamation, and site maintenance as well as others areas. These responsibilities are extensive and the documentation regarding them is voluminous; only those portions of the regulations relating to waste handling, treatment, and disposal will be summarized herein.

Historically the Bureau of Land Management has regulated oil and gas activities through "Notice to Lessees." The requirements of current notices are described below. The Bureau is working to revise all notices into Oil and Gas Orders, which will be Federally promulgated. To date, Oil and Gas Order No. 1 has been issued. Other oil and gas orders are expected to be promulgated in the next year.

DRILLING

The Bureau of Land Management considers reserve pits, and some other types of pits, as temporary. Notice to Lessees 2B contains the following provisions for "Temporary Use of Surface Pits:"

> Unlined surface pits may be used for handling or storage of fluids used in drilling, redrilling, reworking, deepening, or plugging of a well provided that such facilities are promptly and properly emptied and restored upon completion of the operations. Mud or other fluids contained in such pits shall not be disposed of by cutting the pits walls without the prior authorization of the District Engineer. Until finally restored, unattended pits must be fenced to prevent access by livestock and wildlife. Unless otherwise specified by the District Engineer, unlined pits may be used for well evaluation purposes for a period of 30 days.

Land spreading of drilling and reworking wastes by breaching pit walls is allowed when approved by the District Engineer.

PRODUCTION

Produced waters may be disposed into the subsurface, either for enhanced recovery of hydrocarbon resources or for disposal. The operator must present detailed information regarding the proposed disposal site, including subsurface configuration of the proposed injection well, to the Bureau of Land Management prior to approval to inject. This documentation is required to ensure that the injected wastes will be confined to a receiving formation of poor quality. Further, the operator must identify the sources of the produced water, must submit estimated daily quantities of produced water, and must submit an analysis of the water. The analysis is limited to total dissolved solids, pH, chlorides, and sulfates.

The Bureau of Land Management also permits disposal of produced water into lined and unlined pits. "Lined and unlined pits approved for water disposal shall:

1. Have adequate storage capacity to safely contain all produced water even in those months when evaporation rates are at a minimum.

2. Be constructed, maintained, and operated to prevent unauthorized surface discharges of water. Unless surface discharge is authorized, no siphon, except between pits, will be permitted.

3. Be fenced to prevent livestock or wildlife entry to the pit, when required by the District Engineer.

4. Be kept reasonable free from surface accumulations of liquid hydrocarbons by use of approved skimmer pits, settling tanks, or other suitable equipment.

5. Be located away from the established drainage patterns in the area and be constructed so as to prevent the entrance of surface water."

For disposal into lined pits, the operator must submit:

- Site identification
- Planned waste quantities
- Net evaporation data
- Method of disposal for accumulated solids
- Information documenting the liner material and the impervious nature of the proposed liner
- Method used for leak detection

The operator must submit a water analysis "which include the concentrations of chlorides, sulfates, and other constituents which are toxic to animal, plant, or aquatic life." No list of required analytes is included in the Notice.

Leak detection is required for all lined produced water disposal pits. The recommended detection system is an "underlying gravel-filled sump and lateral system." Other systems may be considered acceptable upon application and evaluation.

Oil and gas operators may be permitted to use unlined pits on any one of the following bases: If the pit will receive 5 barrels or less of water per day (monthly basis), no permit is required. If the water contains less than 5,000 ppm total dissolved solids, and does not contain "objectionable levels of any constituent toxic to animal plant, or aquatic life," use of unlined pits is allowed. If the water will be used for wildlife watering, irrigation, or livestock watering, unlined pits may be used. Unlined pits may be used when the produced water is of better quality than surface or subsurface waters of the area. Unlined pits permitted for surface discharges under the National Pollutant Discharge Elimination System are also allowed.

Operators are required to provide information regarding the sources and quantities of produced water, topographic map, evaporation rates, estimated soil percolation rates, and "depth and extent of all usable water aquifers in the area."

REFERENCES

Personal communication with Mr. Steve Spector September 23, 1986.

U.S. Land Management, "Federal Onshore Oil and Gas Leasing and Operating Regulations. Not dated.

43 CFR 3100 (entire group)

U.S. Bureau of Land Management, NTL-2B.

U.S. Department of the Interior - Geological Survey Division. " Notice to Lessees and Operators of Federal and Indian Oil and Gas Leases (NTL-2B)," not dated.

U.S. ENVIRONMENTAL PROTECTION AGENCY
EFFLUENT LIMITATIONS GUIDELINES

On October 30, 1976, the Interim Final BPT Effluent Limitations Guidelines for the Onshore Segment of the Oil and Gas Extraction Point Source Category were promulgated. [41 FR 44942] The rulemaking also proposed Best Available Technology Economically Achievable (BAT), and New Source Performance Standards (Table 1).

On April 13, 1979, BPT Effluent Limitations Guidelines were promulgated for the Onshore Subcategory, Coastal Subcategory, and the Agricultural and Wildlife Water Use Subcategory of the Oil and Gas Extraction Industry. [44 FR 22069] Effluent limitations were reserved for the Stripper Subcategory due to lack of technical data.

The 1979 BPT regulation established a zero discharge limitation for all wastes under the Onshore Subcateogy. Zero discharge Agricultural and Wildlife Subcategory limitations were established, except for produced water which has a 35 mg/l oil and grease limitation.

The American Petroleum Institute (API) challenged the 1979 regulation (including the BPT regulations for the Offshore Subcategory). [661 F.2D.340(1981)] The court remanded EPA's decision transferring 1,700 wells from the Coastal to the Onshore Subcategory. [47 FR 31554] The court also directed EPA to consider special discharge limits for gas wells. Table 2 provides regulatory details related to onshore oil and gas activities.

TABLE 1. SUMMARY OF MAJOR REGULATORY ACTIVITY RELATED TO ONSHORE OIL AND GAS

October 13, 1976 -	Interim Final BPT Effluent Limitations Guidelines and Proposed (and Reserved) BAT Effluent Limitations Guidelines and New Source Performance Standards for the Onshore Segment of the Oil and Gas Extraction Point Source Category
April 13, 1979 -	Final Rules - BPT Final Rules for the Onshore, Coastal, and Wildlife and Agricultural Water Use Subcategories - Stripper Oil Subcategory Reserved - BAT and NSPS never promulgated
July 21, 1982 -	Response to American Petroleum Institute vs EPA Court Decision - Recategorization of 1700 "onshore" wells to Coastal Subcategory - Suspension of regulations for Santa Maria Basin, California - Planned reexamination of marginal gas wells for separate regulations

TABLE 2. ONSHORE SEGMENT SUBCATEGORIES

- ONSHORE:
  - BPT LIMITATION
    - -- ZERO DISCHARGE
  - DEFINED: NO discharge of wastewater pollutants into navigable waters from ANY source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).
- STRIPPER (OIL WELLS):*
  - CATEGORY RESERVED
  - DEFINED: TEN barrels per well per calendar day or less of crude oil.
- COASTAL
  - BPT LIMITATIONS
    - -- No Discharge of Free Oil (No Sheen)
    - -- Oil and Grease: 72 mg/l (Daily)
48 mg/l (Average Monthly)
(Produced Waters)
  - DEFINED: Any body of water landward of the territorial seas, or any wetlands adjacent to such waters.
- WILDLIFE AND AGRICULTURE USE
  - BPT LIMITATIONS
    - -- Oil and Grease: 35 MG/L (Produced Waters)
    - -- Zero Discharge: ANY Waste Pollutants
  - DEFINED: That produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses ... west of the 98th meridian.

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*This subcategory does not include marginal gas wells.

UNDERGROUND INJECTION CONTROL

The Underground Injection Control (UIC) Program was established under Part C of the Safe Drinking Water Act (SDWA) to provide minimum standards for procedural and technical requirements for individual State and Federal UIC Programs. Part C of the SDWA requires the EPA to: (1) identify a list of States for which UIC programs may be necessary; (2) approve or disapprove, in whole or in part, UIC programs submitted by the listed States; and (3) develop programs and regulate those States that do not have approved UIC programs. The Federal UIC Program is defined in 40 CFR Parts 144, 145, and 146.

Table 3 is a list of States having full or partial primacy over their particular UIC Programs. The second column from the left in Table 3 lists the section of the SDWA under which the States applied for approval of their UIC Programs. The third column from the left lists the classes of wells, defined in Table 4, for which primacy has been given. The classes of wells that a State can regulate depend upon the SDWA section under which a State's authority is granted. Section 1422 was originally designed to cover all classes of wells. Brine disposal injection wells were later addressed specifically in Section 1425, which was created by Congress (Dec. 5, 1980) to further define the conditions by which these wells would be regulated. In essence, a State may show that it has a program already in place that has been effective in protecting underground sources of drinking water and that includes record keeping, reporting, permitting, and inspections authority over Federal agencies, and assurance that authorized wells do not endanger underground sources of drinking water.

Minimum standards for UIC programs as defined in 40 CFR 144, 145, and 146 include, respectively, permitting requirements, guidance to obtain approval for State primacy, and technical criteria and standards to be met in permits and authorizations. Part 144 also serves as part of the UIC program for States to be administered by EPA. Part 147 lists and sets specific criteria for those States whose UIC programs are administered by EPA.

TABLE 3. UIC PRIMACY STATES (PROGRAMS APPROVED)

Date June 9, 1986

STATE	TYPE	CLASSES	DATE APPROVED	FR CITE
Oklahoma	1425	II	December 2, 1981	46 FR 58488
Texas	1422	I, III, IV, V	January 6, 1982	47 FR 618
New Mexico	1425	II	February 5, 1982	47 FR 5412
Louisiana*	1422/25	I - V	April 23, 1982	47 FR 17487
Texas*	1425	II	April 23, 1982	47 FR 17488
Oklahoma*	1422	I, III, IV, V	June 24, 1982	47 FR 27273
Arkansas	1422	I, III, IV, V	July 6, 1982	47 FR 29236
Alabama	1425	II	August 2, 1982	47 FR 33268
New Hampshire*	1422	I - V	September 21, 1982	47 FR 41561
Utah	1425	II	October 8, 1982	47 FR 44561
Wyoming	1425	II	November 22, 1982	47 FR 52434
Massachusets*	1422	I - V	November 23, 1982	47 FR 52705
Utah*	1422	I, III, IV, V	January 19, 1983	48 FR 2321
Nebraska	1425	II	February 3, 1983	48 FR 4777
Florida**	1422	I, III, IV, V	February 7, 1983	48 FR 5556
California**	1425	II	February 11, 1983	48 FR 6336
Guam*	1422	I - V	May 2, 1983	48 FR 19717
New Mexico*	1422	I, III, IV, V	July 11, 1983	48 FR 31640
Wyoming*	1422	I, III, IV, V	July 15, 1983	48 FR 32343
New Jersey*	1422	I - V	July 15, 1983	48 FR 32343
North Dakota	1425	II	August 23, 1983	48 FR 38237
Ohio	1425	II	August 23, 1983	48 FR 38238
Alabama*	1422	I, III, IV, V	August 25, 1983	48 FR 38640
Maine*	1422	I - V	August 25, 1983	48 FR 38641
Mississippi**	1422	I, III, IV, V	August 25, 1983	48 FR 38641
Wisconsin*	1422	I - V	September 30, 1983	48 FR 44783
Kansas	1422	I, III, IV, V	December 2, 1983	48 FR 54350
Missouri	1425	II	December 2, 1983	48 FR 54349
West Virginia*	1422/25	I - V	December 9, 1983	48 FR 55127
Illinois	1425	II	February 1, 1984	49 FR 3990
Illinois*	1422	I, III, IV, V	Feburary 1, 1984	49 FR 3991
Kansas*	1425	II	February 9, 1984	49 FR 4735
Arkansas*	1425	II	March 26, 1984	49 FR 11179
Connecticut*	1422	I - V	March 26, 1984	49 FR 11179
Colorado**	1425	II	April 2, 1984	49 FR 13040
Delaware*	1422	I - V	April 5, 1984	49 FR 13525
Maryland*	1422	I - V	April 19, 1984	49 FR 15553
North Carolina*	1422	I - V	April 19, 1984	49 FR 15553
Georgia*	1422	I - V	April 19, 1984	49 FR 15553
Nebraska*	1422	I, III, IV, V	June 12, 1984	49 FR 24134
Vermont*	1422	I - V	June 22, 1984	49 FR 25633
South Carolina*	1422	I - V	July 10, 1984	49 FR 28057
Rhode Island*	1422	I - V	August 1, 1984	49 FR 30698
Washington*	1422	I - V	August 9, 1984	49 FR 31875
North Dakota*	1422	I, III, IV, V	September 21, 1984	49 FR 37065
Oregon*	1422/25	I - V	September 25, 1984	49 FR 37593
South Dakota**	1425	II	October 24, 1984	49 FR 42728
Ohio*	1422	I, III, IV, V	November 29, 1984	49 FR 46896
Idaho*	1422	I - V	June 7, 1985	50 FR 23956
Missouri*	1422	I, III, IV, V	July 17, 1985	50 FR 28941
CNMI*	1422	I - V	July 17, 1985	50 FR 28942
Alaska**	1425	II	May 6, 1986	51 FR 16683

*Full primacy, as of date indicated
**Partial primacy

TABLE 4. CLASSIFICATION OF INJECTION WELLS

Class I	o	Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to inject hazardous waste beneath the lowermost formation containing, within one quarter (1/4) mile of the well bore, an underground source of drinking water.
	o	Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.
Class II		Wells used to inject fluids:
	o	Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection;
	o	For enhanced recovery of oil or natural gas; and
	o	For storage of hydrocarbons which are liquid at standard temperature and pressure.
Class III		Wells used to inject for extraction of minerals including:
	o	Mining of sulfur by the Frasch process.
	o	In situ production of uranium or other metals. This category includes only in situ production from ore bodies which have not been conventionally mined. Solution mining of conventional mines such as stopes leaching is included in Class V.
	o	Solution mining of salts or potash.
Class IV	o	Wells used by generators of hazardous waste or of radioactive waste, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste into a formation which within one quarter (1/4) mile of the well contains an underground source of drinking water.

TABLE 4. CLASSIFICATION OF INJECTION WELLS
(Continued)

Class IV (Cont'd)	o Wells used by generators of hazardous waste or of radioactive waste, by owners or operators of hazardous waste management facilities or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste above a formation which within one quarter (1/4) mile of the well contains an underground source of drinking water.
	o Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to dispose of hazardous waste, which cannot be classified under Sect. 146.05(a)(1) or 146.05(d) (1) and (2) (e.g., wells used to dispose of hazardous wastes into or above a formation which contains an aquifer which has been exempted pursuant to Sect. 146.04).
Class V	o Injection wells not included in Class I, II, III, or IV.

REFERENCES

Federal Register, 40 CFR Parts 144, 145, 146, and 147.

Safe Drinking Water Act, Part C, December 16, 1974, as amended by PL 96-502, December 5, 1980.

Personal Communication with Mr. Mario Salazar, U.S. EPA UIC Program, October 7, 1986. Telephone 202- 382-5561.

Appendix B

Glossary of Terms and Abbreviations

APPENDIX B

GLOSSARY AND ABBREVIATIONS

Annular Injection. Long-term disposal of wastes between the outer wall of the drill stem or tubing and the inner wall of the casing or open hole.

Annulus or Annular Space. The space between the drill stem and the wall of the hole or casing.

Barite. Barium sulfate. An additive used to weight drilling mud.

Barrel. Forty-two United States gallons at 60°F.

Bentonite. A clay additive used to increase the viscosity of drilling mud.

Blowout. A wild and uncontrolled flow of subsurface formation fluids at the earth's surface.

Blowout Preventer (BOP). A device to control formation pressures in a well by closing the annulus when pipe is suspended in the well or by closing the top of the casing at other times.

Brackish Water. Water containing low concentrations of any soluble salts.

Brine. Water saturated with or containing a high concentration of common salt (sodium chloride); also any strong saline solution containing other salts such as calcium chloride, zinc chloride, calcium nitrate, etc.

BS&W. Bottom sediment and water carried with the oil. Generally, pipeline regulation limits BS&W to 1 percent of the volume of oil.

Casing. Large steel pipe used to "seal off" or "shut out" water and prevent caving of loose gravel formations when drilling a well. When the casings are set, drilling continues through and below the casing with a smaller bit. The overall length of this casing is called the string of casing. More than one string inside the other may be used in drilling the same well.

Centralized Brine Disposal Pit. An excavated or above grade earthen impoundment remotely located from the oil or gas operations from which it receives produced fluids (brine). Centralized pits usually receive fluids from many wells, leases, or fields.

Centralized Combined Mud/Brine Disposal Pit. An excavated or above grade earthen impoundment remotely located from the oil or gas operations from which it receives produced fluids (brine) and drilling fluids. Centralized pits usually receive fluids from many wells, leases, or fields.

Centralized Mud Disposal Pit. An excavated or above grade earthen impoundment remotely located from the drilling operations from which it receives drilling muds. Centralized pits usually receive fluids from many drilling sites.

Centralized Treatment Facilities (Mud or Brine). Any facility accepting drilling fluids or produced fluids for processing. This definition encompasses municipal treatment plants, private treatment facilities, or publicly owned treatment works for treatment of drilling fluids or produced fluids. These facilities usually accept a spectrum of wastes from a number of oil, gas, or geothermal sites, or in combination with wastes from other sources.

Centrifuge. A device for the mechanical separation of solids from a liquid. Usually used on weighted muds to recover the mud and discard solids. The centrifuge uses high-speed mechanical rotation to achieve this separation as distinguished from the cyclone-type separator in which the fluid energy alone provides the separating force.

Chemical-Electrical Treater. A vessel that utilizes surfactants, other chemicals, and an electrical field to break oil-water emulsions.

Christmas Tree. Assembly of fittings and valves at the tip of the casing of an oil well that controls the flow of oil from the well.

Circulate. The movement of fluid from the suction pit through pump, drill pipe, bit annular space in the hole, and back again to the suction pit.

Clean Water Act. The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et sea.), as amended by the Clean Water Act of 1977 (P. L. 95-217).

Closed-In. A well capable of producing oil or gas, but temporarily not producing.

Completion Operations. Work performed in an oil or gas well after the well has been drilled to the point where the production string of casing is to be set, including setting the casing, perforating, artificial stimulation, production testing, and equipping the well for production, all prior to the commencement of the actual production of oil or gas in paying quantities, or in the case of an injection or service well, prior to when the well is plugged and abandoned.

Condensate. Hydrocarbons that are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or at the surface.

Conduction Dominated System. A geothermal energy system created by thermal conduction of heat from deep within the earth to the surface.

Connate Water. Water that probably was laid down and entrapped with sedimentary deposits, as distinguished from migratory waters that have flowed into deposits after they were laid down.

Cuttings. Small pieces of formation that are the result of the chipping and/or crushing action of the bit.

Cyclone. Equipment, usually cyclone type, for removing drilled sand from the drilling mud stream and from produced fluids.

Derrick and Substructure. Combined foundation and overhead structure to provide for the hoisting and lowering necessary for drilling.

Desilter. Equipment, normally cyclone type, for removing extremely fine drilled solids from the drilling mud stream.

Development Facility. Any fixed or mobile structure addressed by this document that is engaged in the drilling and completion of productive wells.

Disposal Well. A well through which water (usually salt water) is returned to subsurface formations.

Drill Cuttings. Particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

Drilling Fluid. The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-base drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspended medium for solids, whether or not oil is present. An oil-base drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase.

Drilling Fluids. Drilling fluids are circulated down the drill pipe and back up the hole between the drill pipe and the walls of the hole, usually to a surface pit. Drilling fluids are used to lubricate the drill bit, to lift cuttings, to seal off porous zones, and to prevent blowouts. There are two basic drilling media: muds (liquid) and gases. Each medium is comprised of a number of general types. The type of drilling fluid may be further broken down into numerous specific formulations.

Drill Pipe. Special pipe designed to withstand the torsion and tension loads encountered in drilling.

Emulsion. A substantially permanent heterogeneous mixture of two or more liquids (which are not normally dissolved in each other), but which are held in suspension or dispersion, one in the other, by mechanical agitation or, more frequently, by adding small amounts of substances known as emulsifiers. Emulsion may be oil-in-water or water-in-oil.

Enhanced Oil Recovery. The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool. These artificial means or applications include pressuring, cycling, pressure maintenance, or injection to the pool of a substance or form of energy, but do not include the injection in a well of a substance or form of energy for the sole purpose of (1) aiding in the lifting of fluids in the well, or (2) stimulating the reservoir at or near the well by mechanical, chemical, thermal, or explosive means.

EPA. United States Environmental Protection Agency.

Exploration Facility. Any fixed or mobile structure addressed by this document that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

Field. The area around a group of producing wells.

Flocculation. The combination or aggregation of suspended solid particles in such a way that they form small clumps or tufts resembling wool.

Flowing Well. A well that produces oil or gas without any means of artificial lift.

Fluid Injection. Injection of gases or liquids into a reservoir to force oil toward and into producing wells.

Formation. Various subsurface geological strata penetrated by well bore.

Fractionation. A process of separating various hydrocarbons from natural gas or oil as they are produced from the ground.

Fracturing. Application of excessive hydrostatic pressure that fractures the well bore (causing lost circulation of drilling fluids).

Free Water Knockout. An oil/water separation tank at atmospheric pressure.

Gas-Oil Ratio. Number of cubic feet of gas produced with a barrel of oil.

Gathering Line. A pipeline, usually of small diameter, used in gathering crude oil from the oil field to a point on a main pipeline.

GC. Gas chromatography.

Geothermal Energy. Defined broadly, includes all of the heat within the interior of the earth. For the purposes of this report, it includes the potentially useful part of this energy supply that is represented by crustal rocks, sediments, volcanic deposits, water, steam, and other gases that are at usefully high temperatures, are accessible from the earth's surface, and from which it may be possible to extract useful heat energy.

Gun Barrel. An oil-water separation vessel.

Header. A section of pipe into which several sources of oil, such as well streams, are combined.

Heater-Treater. A vessel used to break oil water emulsion with heat.

Hot Igneous System. A geothermal energy system created by magma chambers near the earth's surface.

Hydrocarbon Ion Concentration. A measure of the acidity or alkalinity of a solution, normally expressed as pH.

Hydrostatic Head. Pressure that exists in the well bore due to the weight of the column of drilling fluid; expressed in pounds per square inch (psi).

Hydrothermal System. A geothermal energy system consisting of high temperature water and/or steam which is transported near to the surface by the convective circulation through faults and fractures.

Hyperthermal Fields. (1) Wet Fields - producing pressurized water at temperatures exceeding 100°C, so that when the fluid is brought to the surface and its pressure is reduced, a fraction is flashed into steam while the majority of it remains as boiling water. (2) Dry Fields - producing dry saturated, or slightly superheated, steam at pressures above atmospheric.

Inhibitor. An additive that prevents or retards undesirable changes in the product. Particularly, oxidation and corrosion, and sometimes paraffin formation.

Injection. Introduction of drilling fluids or produced fluids into an underground geologic formation, usually for disposal purposes.

Invert Oil Emulsion Drilling Fluid. A water-in-oil emulsion where fresh or salt water is the dispersed phase and diesel, crude, or some other oil is the continuous phase. Water increases the viscosity and oil reduces the viscosity.

Killing a Well. Bringing a well under control that is blowing out. Also, the procedure of circulating water and drilling fluids into a completed well before starting well servicing operations.

Location (Drill Site). Place at which a well is to be or has been drilled.

Low Grade Aquifers. Capable of producing useful hot water of low grade (ranging up to 70°C) because of a temperature gradient.

Marginal Well. An oil or gas well that produces such a small volume of hydrocarbons that the gross income therefrom provides only a small margin of profit or, in many cases, does not even cover the cost of production. ("Marginal well" should be distinguished from the definition for "stripper well" in 44 FR 22073.)

Mud Pit. A steel or earthen tank that is part of the surface drilling mud system.

Mud Pump. A reciprocating, high pressure pump used for circulating drilling mud.

Multiple Completion. A well completion that provides for simultaneous production from separate zones.

NPDES Permit. A National Pollutant Discharge Elimination System permit issued under Section 402 of the Clean Water Act.

96-hr LC-50. The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay after 96 hours of constant exposure.

Onsite Air Drilling Pit. An excavated or above grade earthen impoundment on a well site that holds fluids produced by or associated with the air drilling process. These fluids include but are not limited to: connate water, fresh water (for dust suppression), stimulation fluids, completion fluids, and drilling additives.

Onsite Drilling Mud (Reserve) Pit. An excavated or above grade earthen impoundment on a well site that holds drilling mud, connate water, stimulation fluids, completion fluids, or other waste produced by or associated with drilling.

Onsite Pit Treatment. Treatment of pit contents in situ, or on the drilling site by the operator. Neutralization, aeration, and settling (or some combination thereof) are routine onsite pit treatment technologies. Reverse osmosis is a rare but available onsite pH treatment.

Priority Pollutants. The 65 pollutants and classes of pollutants declared toxic under Section 307(a) of the Act. Appendix C contains a listing of specific elements and compounds.

Production Facility. Any platform or fixed structure addressed by this document that is used for active recovery of hydrocarbons from producing formations.

Produced Fluids. All of the liquid and gaseous materials yielded by a well, excluding fluids introduced into the well for enhancement of productivity. In this document, the term "produced fluids" is normally construed as the non-product portion of the fluids yielded by a well. In this context, produced fluids are principally brines.

Produced Water. The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. It can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Produced Sand. Slurried particles used in hydraulic fracturing, and the accumulated formation sands and scale particles generated during production.

Publicly Owned Treatment Works (POTWs). A treatment facility as defined by Section 212 of the Clean Water Act, which is owned by a State or municipality. An "approved POTW treatment program" or "Program" or "Pretreatment Program" means a program administered by a POTW that meets the requirements established in 40 CFR 403, and which has been approved by a Regional Administrator or State Director in accordance with 40 CFR 403.

RCRA. The Resource Conservation and Recovery Act of 1976, as amended.

Semithermal Fields. Capable of producing hot water at temperatures up to approximately 100°C from depth of 1 to 2 km.

Separation. A process whereby liquid hydrocarbons are separated from gas. The term is sometimes used to describe a relatively simple process distinguished from fractionation.

Stimulation. Any action taken by well operator to increase the inherent productivity of an oil or gas well including, but not limited to, fracturing, shooting, or acidizing, but excluding cleaning out, bailing, or workover operations.

Stripper Wells. Wells in a field producing an average of less than 10 barrels of oil per calendar day per well. Water injection wells and gas wells are excluded from the calculation of average daily oil production for a field.

Supernatant. A liquid or fluid forming a layer above settled solids.

Tank Bottom Sludge. Sediment, oil, water, and other substances that tend to concentrate in the bottom of production field vessels, especially stock tanks, are called field tank bottom sludges. This layer of sludge may be periodically removed to prevent oil contamination.

Treatment Works. Any devices and systems used in the storage, treatment, recycling, and reclamation of municipal sewage or industrial wastes of a liquid nature to implement Section 201 of the Act, or necessary to recycle or reuse water at the most economical cost of the estimated life of the works, including intercepting sewers, outfall sewers, sewage collection systems, pumping, power, and other equipment and their appurtenances thereof; extensions, improvements, remodeling, additions, and alterations thereof; elements essential to providing a reliable recycled supply such as standby treatment units and clear well facilities; and any works, including site acquisition of the land that will be an integral part of the treatment process (including land use for the storage of treated wastewater in land treatment facilities prior to land application) or is used for ultimate disposal of residues resulting from such treatment.

"Treatment works" means any other method or system for preventing, abating, reducing, storing, treating, separating, or disposing of municipal waste, including waste combined with storm water and sanitary sewer systems.

Well Completion. In a potentially productive formation, the completion of a well in a manner to permit production of oil; the walls of the hole above the producing layer (and within it if necessary) must be supported against collapse and the entry into the well of fluids from formations other than the producing layer must be prevented. A string of casing is always run and cemented at least to the top of the producing layer, for this purpose. Some geological formations require the use of additional techniques to "complete" a well such as casing the producing formation and using a "gun perforator" to make entry holes, using slotted pipes, consolidating sand layers with chemical treatment, and using surface-actuated underwater robots for offshore wells.

Workover. To clean out or otherwise work on a well in order to increase or restore production. A typical workover is cleaning out a well that has sanded up. Tubing is pulled, the casing and bottom of the hole washed out with mud, and (in some cases) explosives set off in the hole to dislodge the silt and sand.

Workover Fluids. Any type of fluid used in the workover operation of a well.